<u>İSTANBUL TECHNICAL UNIVERSITY ★ INSTITUTE OF SCIENCE AND TECHNOLOGY</u>

DESIGNING AN UNDERGROUND GAS STORAGE FIELD USING THE RUBIS SOFTWARE

M.Sc. Thesis by
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Department : Petroleum and Natural Gas Engineering

Programme : Petroleum and Natural Gas Engineering

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RUBIS YAZILIMI KULLANARAK BİR YERALTI GAZ DEPOLAMA SAHASININ TASARIMI

YÜKSEK LİSANS TEZİ

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FOREWORD

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(Petroleum and Natural Gas Engineer)

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ABBREVIATIONS

ERD **:** Extended Reach Drilling
UGS **:** Underground Gas Storage
TCF **:** Trillion Cubic Feet
EIA **:** Energy Information Administration of DOE/ USA
WOC **:** Water Oil Contact
GOC **:** Gas Oil Contact
HC **:** Hydrocarbon

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DESIGNING AN UNDERGROUND GAS STORAGE FIELD USING THE RUBIS SOFTWARE

SUMMARY

Natural gas has been known to be a very useful energy source. In the early days of the natural gas industry, the gas was mainly used to light streetlamps and houses. However, with much improved distribution and technological advancements, natural gas is being used in different areas. According to the EIA (Energy Information Administration) in 2009, 21% of natural gas is used in the residential sector, 31% in the electric power sector, 13% in the commercial sector, 32% in the industrial sector and 3% in the transportation sector in the UAS.

The demand of natural gas is not uniformly distributed through the year. Residential consumption varies from minimum values during the summer to a maximum in winter. In cold seasons, the natural gas demand increases because of space heating consumption. This problem of balancing supply and demand can be handled effectively by storage of natural gas. Stored natural gas can act as insurance if any unforseen accidents, natural disasters, or unexpected consumer demand fluctuation occur. Also, stored natural gas ensures that any excess supply delivered during the summer months is available to meet the increased demand of the winter months.

Natural gas could be stored in various types, either aboveground or underground, to honor variations in demand.

Natural gas can be stored in pipelines by increasing the pressure. After World War II, the natural gas industry noted that seasonal demand increases could not be met by pipeline delivery alone. The low capacity of pipelines are suitable only to overcome hourly varying demands.

High pressure steel tanks are another type of aboveground storage. The gas compressed under high pressure and stored in steel tanks. Similar to storage in pipeline, the storage capacity is low. In addition, the cost of installment and operation process of such facilities are high.

Natural gas storage as LNG is one of the aboveground storage types. The gas is stored at low temperatures of -162°C. Since the liquification and gasification processes are costly, the storage in LNG forms should only be used when other feasible storage operations are not possible.

Other way of storing natural gas is storing in underground. The salt deposits are found in two forms: salt beds, or salt domes. Salt beds are more prominent and consist of a thinner layer of salt. They are usually not as dense as a salt dome nor as deep, for these reasons salt beds are less popular than salt domes for salt cavern construction. The salt caverns have the high deliverability, but are not always located near the consumer markets. Additionally the cavern’s operation is costly.

An aquifer is suitable for gas storage if the water bearing sedimentary rock formation is overlaid with an impermeable cap rock. Also, the aquifer helps to maintain base gas pressure and to decrease the base gas capacity.

Depleted gas reservoirs are the most common type of natural gas storage. They are the most economical and easiest to develop, operate and maintain. They have already been tapped of their recoverable natural gas and just need to be filled again. From a practical stand point, using an already developed reservoir allows the use of equipment left behind from when the field was last productive.

The other important factor in depleted oil/gas reservoir is assurance of deliverability. The storage reservoir should be able to deliver 50% or more of its original content within a 3 or 4 month period. Then more wells should be drilled to increase the deliverability of the reservoir.

In this study the X gas field is modelled as a storage pool. The purpose of the modelling is to determine number of wells due to two different criteria considered in this study. In the first criterion, the number of wells is determined based on desired peak day requirements. In the second criterion the number of wells is determined in terms of wellhead flowing pressure constraints. The reservoir performance is modelled by using the RUBIS software.

First the number of wells for various wellhead pressures in vertical wells is determined. The number of wells becomes 30 if the wellhead flowing pressure is 70 bars. The effect of skin factor on the number of vertical wells is investigated. Increasing the skin factor causes an increase in required number of wells to maintain the desired peak day requirements. The well length in horizontal wells has significant effect on the number of wells required to maintain peak day load. By increasing the well horizontal length, the number of required wells decreases. The required number of wells due to wellhead flowing pressure in vertical wells and horizontal wells is determined. The results show that horizontal wells produce or inject more gas than vertical wells as expectedly.

RUBIS YAZILIMI KULLANARAK BIR YERALTI GAZ DEPOLAMA SAHASININ TASARIMI

ÖZET

Doğal gaz bir yeraltı enerji kaynağı olarak bilinmektedir. Doğal gaz endüstrisinin ilk başlarında, gaz genel olarak sokak lambaları ve evleri aydınlatmada kullanılmaktaydı. Teknolojik gelişmeler ve dağıtımdaki ilerleme ile doğal gaz birçok farklı alanda kullanmaya başladı. EIA' nin verdiği bilgilere göre, 2009 yılında, ABD'de doğal gazın %21'i evlerde, %31'i elektrik enerjisi sektöründe, %13'ü ticari sektörde, %32'si endüstriyel sektöründe ve % 3'ü de taşıma sektöründe kullanılmıştır.

Doğal gaza talep yıl boyunca değişiklik gösterir. Konutlarda kullanılan gaz yazın minimumdan kışın maksimum miktara değişir. Soğuk aylarda ısıtma sebebi ile doğal gaza talep artar. Arz ve talep dengeleme sorunu, doğal gaz depolaması ile ortadan kalkabilmektedir. Depolanan gaz tahmin edilmeyen kaza ve doğal afetler ve ya beklenmeyen müşteri talepleri nedeniyle dalgalanma oluştuğunda bir sigorta gibi düşünebilmektedir. Ayrıca depolanan doğal gaz yaz aylarında kullanılmayan fazla gazın kışın artan ihtiyaca cevap vermesini sağlar. Doğal gaz değişen ihtiyaca göre gerektiği zaman kullanılmak üzere yeraltında ve ya yüzeyde çeşitli şekillerde depolanabilir. Doğal gazın boru hatlarında depolanması basıncın artırılması ile sağlanır. İkinci Dünya Savaşından sonra doğal gaza artan talebin sadece boru hatları dağıtımı ile karşılanamayacağı ortaya çıkmıştır. Boru hatlarının düşük depolama kapasitesi sadece saatlik ihtiyaçları karşılamak için uygundur. Yüksek basınçlı çelik tanklar doğal gazın yüzeyde depolanmasının başka bir yoludur. Gaz yüksek basınç altında sıkıştırılıp çelik tanklarda depolanır. Bu yöntemde boru hatları gibi düşük kapasiteye sahiptir. Ayrıca bu tesislerin kurulumu ve işletmesi maliyetleri yüksektir. Doğal gaz LNG olarak da yüzeyde depolanabilir. Gaz -162 °C 'de sıvılaştırılıp, depolanır. Sıvılaştırma ve tekrar gaza dönüştürme işlemleri maliyetli olduğu için bu yöntem sadece diğer depolama yöntemleri mümkün olmadığı zaman kullanılır. Doğal gaz yeraltında da depolanabilir, bu yöntemlerden biri tuz yataklarında veya tuz domlarında depolamaktır. İnce tuz tabakalarında oluşan tuz yatakları, tuz domları kadar uygun veya derin değildir. Bu nedenle doğal gaz depolanmasında tuz domları kadar tercih edilmezler. Tuz oyukları yüksek geri üretim kapasitesine sahiptir ama kullanım alanlarına her zaman yakın olmaması ve işletme maliyetlerinin yüksek olması nedeni ile iyi analiz edilmeleri gerekmektedir. Akiferler eğer geçirimsiz örtü kayacı ile kapanmış ise gaz depolanması için uygudur. Akiferler yastık gazı basıncını dengeleyerek yastık gazı ihtiyacını azaltır.

Doğal gaz depolanmasında en çok tükenmiş gas rezervuarları tercih edilir. Çünkü depolanan doğal gazın oluşumundaki yapıya benzerler bu nedenle tükenmiş pek çok doğal gaz rezervuarı, daha sonra bir depolama rezervuarı olarak kullanılmaya başlanmıştır. Üretim sırasında rezervuara ait bütün özellikler elde edildiği için, depolama sahası olarak düsünülen bu yapılara araştırma maliyetleri de düşük olur.

Depolama yapılacak jeolojik yapının boyutları, kayaç özellikleri, geçirgenlik-gözeneklilik ilişkileri, karot bilgileri ve yapıyı oluşturan formasyonun basınca karşı uygunluğu gibi depolama işlemleri için gerekli olan bilgiler üretim sırasında elde edilen verilerin incelenmesi ile kolayca sağlanabilmektedir.

Bu çalışmada, X gaz sahası depolama amacıyla modellenmiştir. Modellemenin amacı farklı kriterlere göre delinmesi gereken kuyu sayılarını bulmaktır. İlk bölümde, kuyu adedi maksimum üretim ihtiyacını karşılayacak şekilde bulunmuştur. İkinci bölümde, kuyu adeti belli aralıktaki kuyubaşı akış basınçlarına göre hesaplanmıştır. Rezervuar performansı RUBIS programı kullanarak modellenmiştir. Sonuçlara göre, maksimum üretim yükünü karşılayacak düşey kuyu sayısı farklı kuyubaşı akış basınçlarına göre hesaplanmıştır; örneğin, 70 barlık kuyubaşı akış basıncında 30 kuyu gerektiği hesaplanmıştır. Zar faktörün artması ile gerekli kuyu sayısının artığı görülmüştür. Yatay kuyu uzunluğunun gerekli kuyu sayısı uzerinde etkili olduğu görülmüştür. Yatay kuyularda düşey kuyulara göre daha fazla geri üretim veya injeksiyon yapılmaktadır.

1. NATURAL GAS

Natural gas is a fossil based fuel in hydrocarbon group which is trapped underground in porous rocks, often in association with petroleum and coal deposits. Natural gas is an odourless and colourless gas with low density and viscosity. Natural gas generally contains a high percentage of methane with smaller amounts of ethane, propane and butane and inert gases such as nitrogen, carbon dioxide, hydrogen sulphide, helium and water vapour. It consists of 80-95% methane and smaller amounts of ethane and propane. The composition of natural gas varies in a wide range. The common composition of natural gas used as fuel is given in Table 1.1. When the natural gas contains significant amounts of carbon dioxide or hydrogen sulphide, it is called sour or acid gas. The average gross heating value of natural gas is approximately 1 020 Btu/SCF, usually varying from 900 to 1 200 Btu/SCF (8009-10679 Kcal/m^3) and specific gravity varies (1 for air) 0.55 to 0.79 (Perry, 1963).

Table 1.1: Typical components of natural gas (Kumar, 1987).

Category	Component	% by volume
Paraffinic HC's	Methane (CH_4)	70-98
	Ethane (C_2H_6)	1-10
	Propane (C_3H_8)	Trace-5
	Butane (C_4H_{10})	Trace-2
	Pentane (C_5H_{12})	Trace-1
	Hexane (C_6H_{14})	Trace-0.5
	Heptane & higher (C_{7+})	None-Trace
Non-hydrocarbon	Carbon dioxide (CO_2)	Trace-1
	Hydrogen Sulfide (H_2S)	Trace occasionally
	Nitrogen (N_2)	Trace-15
	Helium (He)	Trace-5
	Water (H_2O)	Trace-5
	Other sulfur & nitrogen compounds	Trace occasionally

Raw natural gas is a mixture of methane, higher hydrocarbons, inert gases, water vapor, hydrogen sulfide, helium. Contaminants should be removed before delivery to the markets. Some of contaminates are such as acid gases, water vapor, water, condensate and pipeline trash.

Natural gas is a vital component of the world's supply of energy. After it is cleaned of its impurities, fossil gas becomes a clean-burning and efficient source of heat and is used in a wide variety of applications. The maximum consumption of natural gas takes place in the industrial sector. It is mainly used to generate electricity, space heating and etc.

Natural gas is the major source of energy for most consumers. It is a more environment friendly fuel than oil or coal. It is composed of methane, which has just one carbon, producing very low carbon emissions. It is a known fact that for the same amount of heat, natural gas releases 30% less carbon dioxide than burning oil and 45% less carbon dioxide than burning coal. So it burns cleaner than heating oil, and does not leave behind products, like ash. The high heating value is another reason to increase natural gas demand rather to other fossil fuels (Url-1).

The popularity of natural gas as a source of energy has increased over the years leading to an increase in its consumption. Consumption of natural gas is expected to grow significantly in the coming years. Among the energy sources, natural gas ranks second in terms of projected increase in consumption. The maximum consumption of natural gas takes place in the industrial sector. Natural Gas reserves around the world have increased over the years. According to estimates of EIA (Energy Information Administration), global consumption of natural gas is expected to rise from 102.9 trillion cubic feet (2.9 trillion cubic meters) in 2009 to 163 trillion cubic feet (4.6 trillion cubic meters) in 2030. (Url-2). Table 1.2 shows the distribution of proved reserves. As seen, the proved reserves increase by years and the largest amount of gas is held by Middle East. Since the natural gas plays an important role as a clean energy source, the world demands of natural gas increases by years. So when there is demand for natural gas, this results in more production of natural gas.

Table 1.2: Distribution of proved natural gas reserves with years and regions (Url-6).

Natural Gas Proved Reserves by Region (Trillion Cubic Meters)				
Region	1998	1999	2008	2009
North America	9.52	7.32	9.18	9.16
Central & South America	4.80	6.81	7.30	8.06
Europe & Eurasia	52.28	56.17	62.26	63.09
Middle East	37.83	54.74	75.82	76.18
Africa	8.48	11.44	14.71	14.76
Asia Pacific	9.50	12.07	16.00	16.24
World	122.40	148.55	185.28	187.49

Amounts of natural gas production in the world are given in Table 1.3. As seen, the major part of gas production is in the North America and Eurasia regions.

Table 1.3: Distribution of natural gas production with years and regions (Url-6).

Natural Gas Production by Region (Billion Cubic Meters)					
Region	2005	2006	2007	2008	2009
North America	743.6	764.0	783.7	801.8	813.0
Central & South America	138.6	151.1	155.1	157.1	151.6
Europe & Eurasia	1038.0	1051.7	1053.2	1086.3	973.0
Middle East	319.9	339.1	357.4	383.4	407.2
Africa	175.6	192.6	205.2	214.3	203.8
Asia Pacific	363.7	381.7	400	417.9	438.4
World	2779.5	2880.2	2954.7	3060.8	2987.0

Table 1.4 shows the natural gas consumption in the various regions by years. The gas consumption in Africa is less than other regions. The North America and Europe are the major consumers of natural gas. The gas consumption increases by years in the world.

Table 1.4: Distribution of natural gas consumption with years and regions (Url-6).

Natural Gas Consumption by Region (Billion Cubic Meters)					
Region	2005	2006	2007	2008	2009
North America	774.7	771.9	813.9	822.0	810.9
Central & South America	122.5	135.3	138.1	141.0	134.7
Europe & Eurasia	1114.2	1121.4	1135.5	1138.5	1058.6
Middle East	279.2	291.5	303.1	331.8	345.6
Africa	79.4	84.1	90.8	96.1	94.0
Asia Pacific	397.5	425.3	455.8	481.4	496.6
World	2765.5	2829.5	2937.1	3010.8	2940.4

2. NATURAL GAS STORAGE

The storage of natural gas by re-injection into the underground reservoirs has became quite commonplace in various developed countries around the world. The exploration, production, and transportation of natural gas take time, and the natural gas that reaches its destination is not always needed right away, so it is injected into underground storage facilities.

Underground storage has been proved to be one of the most efficient ways of storing gas. Indeed nature has been storing gas under the surface for millions of years. The use of underground storage reservoirs has also been found to be a far cheaper alternative than storing gas in pipelines and tanks that are expensive to build and to maintain. Underground storage is also safer. Natural gas that is stored underground is inert due to the lack of oxygen. That means that gas cannot burn or explode (Dharmananda et al., 2004).

The gas supply chain is characterized by large hourly, daily and annual imbalances between supply and demand. Although on one hand, producers and transporters prefer to deliver the gas at the same constant rate at all times, users only need gas at certain times, during cooking, in winter for heating etc. The most logical solution to this problem is the storage. The excess gas inject to storage pools in summer (when demand is low) and withdrawal in winter (when demand is high) as shown in Figure 2.1 (Katz and Lee, 1981).

Storage is also used as a safeguard against supply interruptions. These can be of a technical nature, such as failures of the production facilities or in the pipeline system. In case of cross-border gas transport, political events in the producing or transit countries might result in temporary reduction or total loss of gas supply. Gas storage facilities fall into two basic categories:

Seasonal: Seasonal storage sites, which may also serve a strategic purpose, must be able to store huge volumes of gas build up during low demand times for slow release during periods of high demand.

Peak: Peak facilities store smaller quantities but must be able to inject gas quickly into the transmission network to meet surges in demand (Evans and Chadwick, 2009).

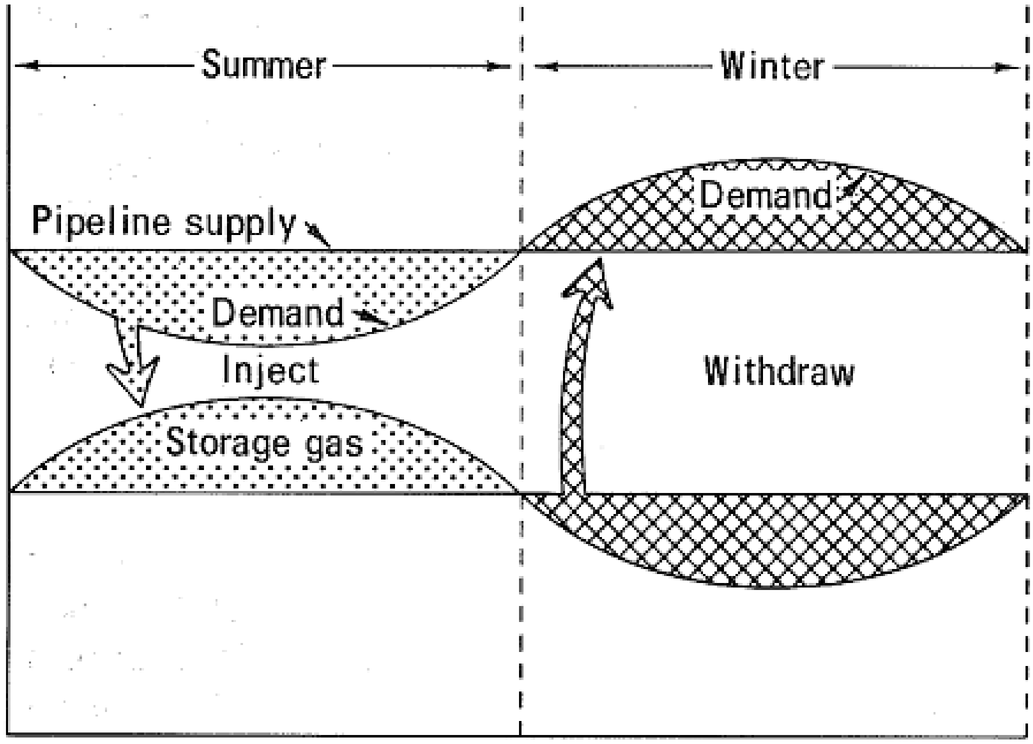

Figure 2.1: Supply and demand curve for natural gas.

The main reasons for the storage of natural gas are:

- Seasonal balancing
- Efficiency
- Coverage of consumption peaks
- Support of transmission flexibility
- Safety reserves

Seasonal balancing compensates the increased gas consumption during winter by the gas stored in underground natural gas storage field. In the summer, due to lower consumption of the gas, the extra gas could be injected to storage fields. In winter during the cold days, the stored gas will be withdrawn from underground storage field to meet the demands.

Efficiency is the other reason to natural gas storage. When the natural gas prices is low, the gas purchased for lower prices and stored in underground natural gas storage fields and subsequently withdrawn in order to consume during the period of higher price. This is a very important factor in countries that depend on the import of natural gas. *Coverage of consumption peaks is* another reason to store of natural gas. Unexpected increase of gas consumption can be quickly satisfied by gas withdrawal from the storage. In this situation mostly peak shaver facilities are used to meet peak demand. These facilities have storage cycles of just few days.

Sometimes gas is stored due to *support of transmission flexibility* to insure against any unforeseen accidents. Gas storage can be used as an insurance that may affect either production or delivery of natural gas and compensates any fluctuations in international gas transmission. These may include natural factors such as hurricanes, earthquakes or malfunction of production or distribution systems. During the critical times such as limitation or interruption of supplies from abroad (wars and political conditions) and also strategically cases *safety reserve* of natural gas could be the important factor in order to maintain of natural gas (Evans and Chadwick, 2009).

Generally types of natural gas storage can be identified and categorized in two groups of surface storage and underground storage. Each of these types of possesses have distinct physical and economic characteristics which govern the suitability of a particular type of storage type for a given application.

Surface natural gas storage:

- Natural gas storage in pipelines
- Storage in LNG form
- Natural gas storage in high pressure tanks

Underground natural gas storage:

- Storage in depleted oil or gas reservoir
- Storage in aquifers
- Storage in salt caverns
- Storage in abandoned mines

2.1 Surface Natural Gas Storage

As mentioned before, the natural gas is stored to respond for seasonal and peak demands. Since storage of natural gas in surface facilities have in terms of the stored limitations such as store in small quantity and also economic issues, it could be used for peak type of demands.

2.1.1 Natural gas storage in pipelines

Pipeline systems are often used as gas storage facilities to store small quantities of natural gas when it is not demanded. Compression stations enable the pressure in the main pipeline system in order to compress the gas and increase the amount of gas and therefore use the system for storage purposes. When the demand increases, the stored gas can be used by decreasing the pressure in the pipeline system allowing the compressed gas flow. The storage capacity of a pipeline can be determined by taking the difference of the amount of gas in the pipe under packed and unpacked conditions. A pipeline is packed when withdrawal from the pipe is at a minimum and the discharge pressure is at a maximum during constant supply and unpacked when withdrawal from the pipe is at a maximum and the discharge pressure is at minimum. Pipeline storage is useful for few hours' intervals (Tureyen, 2000).

2.1.2 Liquefied natural gas storage

Liquefied natural gas was initially used for transportation overseas in spherical tankers where pipelines could not be constructed. A liquefied natural gas storage tank or LNG storage tank is a specialized type of storage tank used for the storage of liquefied natural gas. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state. The common characteristic of LNG storage tanks is the ability to store LNG at the very low temperature of -162 °C (-260 °F). LNG storage tanks have double containers, where the inner container contains LNG and the outer container contains insulation materials. The most common tank type is the full containment tank. Tanks are roughly 55 m (180 ft) high and 75 m (250 ft) in diameter (=250 000 m^3). The world's largest tank (delivered in 2001) has a volume of 200 million liters (Url-3).

In LNG process, the gas is first extracted and transported to a processing plant where it is purified by removing any condensates such as water, oil, mud, as well as other gases like CO_2 and H_2S and sometimes solids as mercury. The gas is then cooled down in stages until it is liquefied. LNG is finally stored in storage tanks and can be loaded and shipped (Url-3).

2.1.3 Natural gas storage in high pressure tanks

Sometimes natural gas is stored in high-pressure tanks, usually at 200-250 bars (2901-3625 psi). The shapes of tanks are mostly spherical or cylindrical. These tanks occupy a lot of space and are heavy that cause additional cost to install and operate of these facilities. In addition, gas compression requires expensive multi-stage high-pressure compression technology. Compressed natural gas is currently the prevailing technology in the natural gas vehicle industry (Url-4).

2.2 Underground Natural Gas Storage

One of the most common types of the underground gas storage is storage in depleted gas/oil fields. This is because these reservoirs have trapped gas/oil previously. If suitable, aquifers can also be used for storing natural gas. Both storage in gas/oil reservoirs and storage in aquifers are examples where the gas is stored in porous media. On the other hand gas can be stored in caverns created artifically in salt caverns, or in abandoned mines.

2.2.1 Storage in salt caverns

Gas storage in salt caverns is a more recent development. The first underground gas storage salt cavern was commissioned in 1961 in Michigan in USA. Salt cavern storage sites are solution mined cavities in existing salt domes/structures. These shallow cavities are filled with injected natural gas and act as high pressure storage vessels.

A salt cavern or cavity is created by dissolving (‘leaching’) the salt, which is present in the subsurface in rock form using solution mining techniques. A well is drilled into a suitable salt formation and, after running and cementing the last casing, two concentric tubular ‘leaching strings’ are run in the hole for the purposes of leaching the cavern. The annulus between the outer leaching string and the casing is filled with either a diesel or nitrogen blanket to prevent leaching of salt around and above the bottom of the casing (casing shoe). To dissolve a cavern in salt, fresh water is circulated into the well through one of the leaching strings and higher density brine produced (withdrawn) through the other leaching string. The shape of the cavern is controlled by changing the depth of these two strings, the depth of the blanket, and the rate and direction of circulation. The shape of the cavern is monitored by periodic running of a sonar survey in the cavern. Salt cavern leaching process and system components are shown in Figure 2.2. Leaching of a cavern takes many months to several years. There are many considerations that need to be fulfilled to make a gas caverns suitable for gas storage. These include:

- Sufficient size/volume
- Short and long term structural stability
- Limited volume decreases (wall convergence due to salt creep)
- Safe containment of the stored material (no gas losses)
- Safe disposing of produced brine.

These requirements mean that not all salt deposits are suitable for gas storage purposes. In salt domes, the preferred cavern shape is that of a vertical cylinder. Caverns in bedded salt usually have volumes in the range 100 000 to 300 000 m^3. Due to the thinner salt bed geometries, the volume of these caverns will be smaller than the volumes of caverns in salt domes. The largest cavern in the world is measuring 400 meter high and 80 meter across (Evans and Chadwick, 2009).

The shape of caverns can be controlled during solution mining process. The relative depths of the leaching strings can be modified to control the shape of the cavern. The shape of cavern is a result of the relative position of freshwater injection and brine withdrawal. There are two types of leaching to determine the caverns shape, direct leaching and inverse leaching. In the *direct leaching* which fresh water is injected through tubing, and brine is withdrawn through the annular space between tubing and the final well casing. The direct leaching is shown in left side of Figure 2.3. Reverse leaching which fresh water is injected through the annulus and brine is withdrawn through the tubing, which is showed in right side of Figure 2.3. More salt is dissolved at the level of water injection, creating a wider cavity at that depth. Injection and withdrawal levels can be modified to control cavern shape.

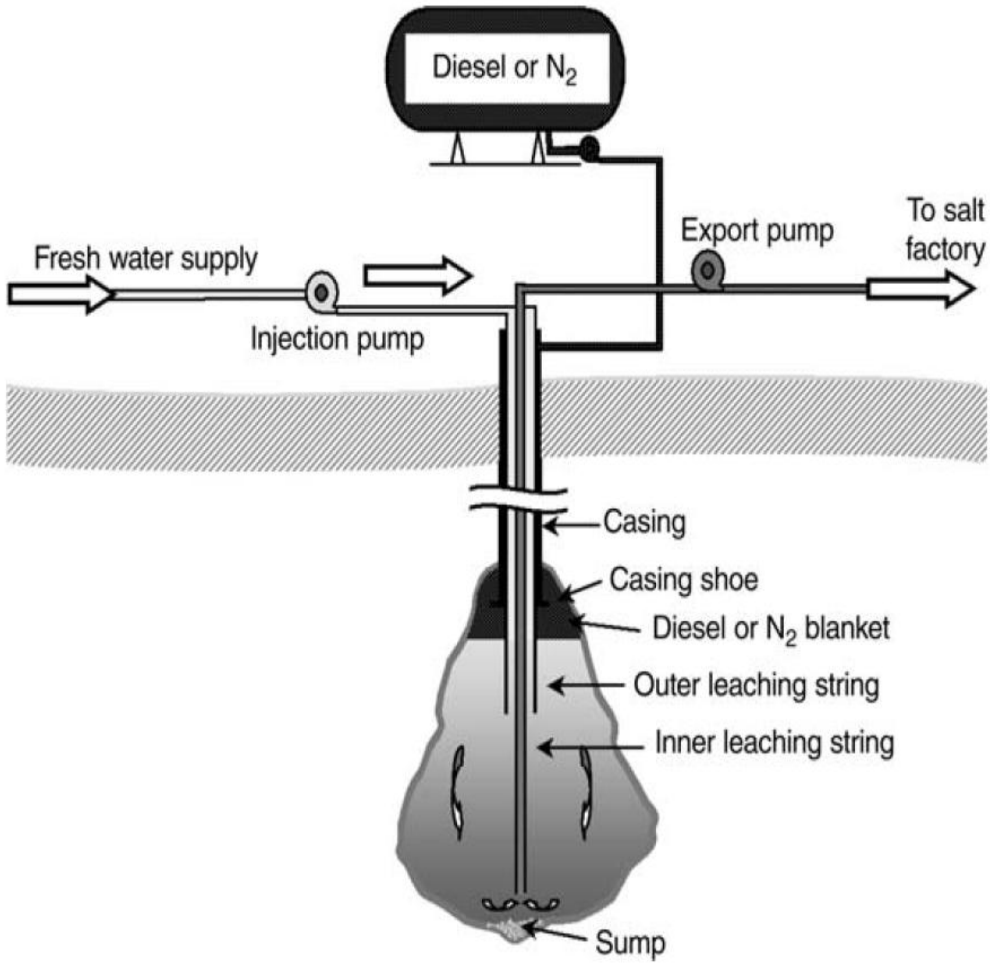

Figure 2.2 : Salt cavern leaching process and system components (Evans and Chadwick, 2009).

Salt is a plastic material that will move slowly under large pressure differences. This plasticity increases at higher temperatures. Since the pressure in a gas storage cavern is lower than the pressure exerted on the salt by the overlying rocks, the salt tends to squeeze towards the cavern centre, gradually reducing the cavern volume (cavern convergence). For caverns at a depth of 1000–1400 m, the convergence rate is usually below 1% of cavern volume per year. At greater depth, both the temperature and the overburden pressure increase, so that the convergence rate increases rapidly. To keep cavern convergence within acceptable limits, shallow depths are preferred. Other issue should be considered, is the large volume of brine (salt saturated water), which has to be disposed of. The preferred way is to use the brine in salt factories for salt production. Other ways include disposal in surface waters, such as rivers or the sea, although this is often not permitted, or the re-injection into an underground porous layer (Evans and Chadwick, 2009; Satman, 2009).

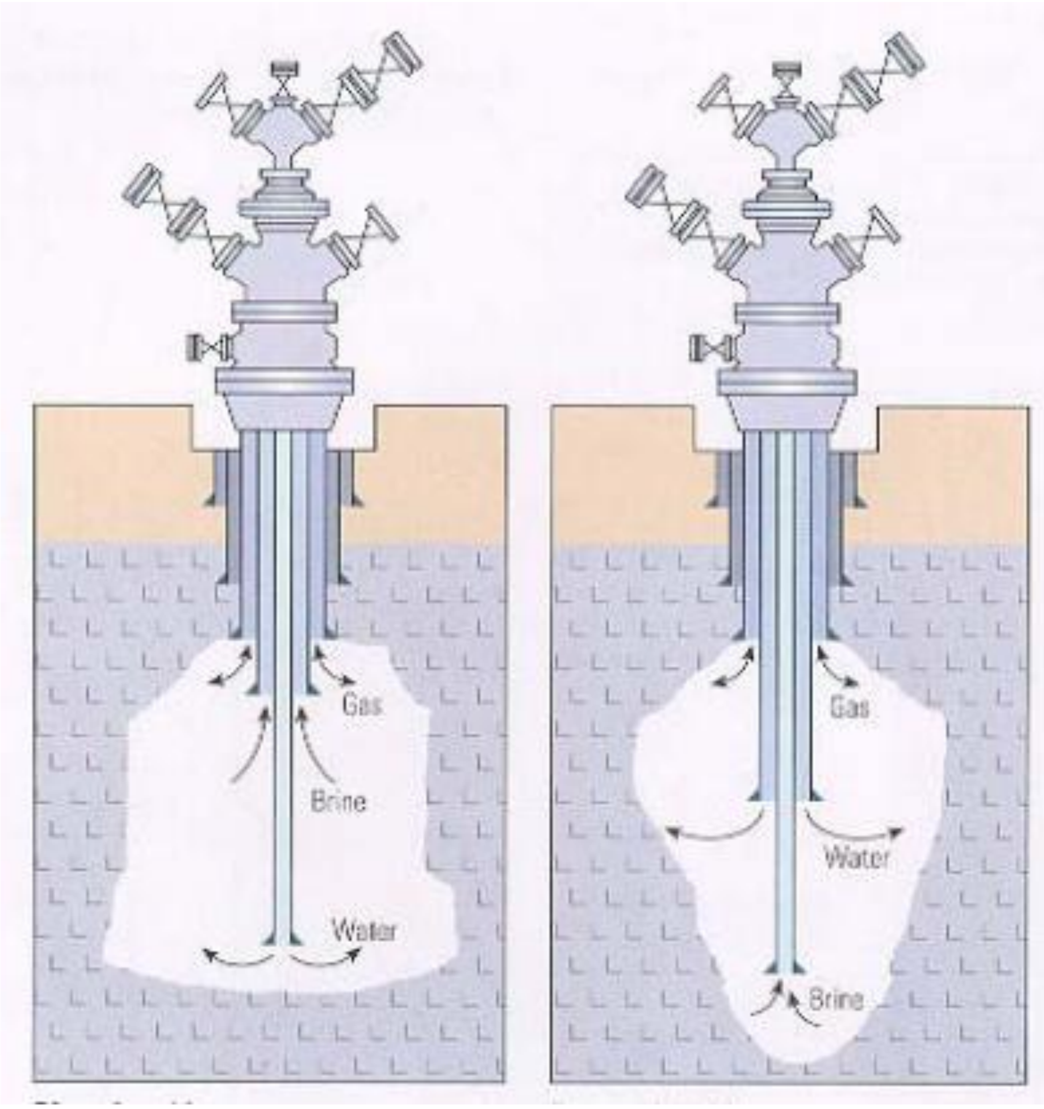

Figure 2.3: Direct leaching (in left) and reverse leaching processes (at right) (Satman, 2009).

Some important advantages of salt caverns are following:

- Low base gas requirements of 25%, which can approach 0% in emergencies.
- Ultra-high deliverability (much higher than depleted reservoir and aquifer storage).
- Operational flexibility as these reservoirs can cycle working gas four to five times a year.
- Salt caverns provide excellent seals (the salt cavern walls are essentially impermeable barriers) and the risk of reservoir gas leaks is small.

Salt caverns are also considered with respect to some disadvantages such as:

- Mostly are located far away from the winter heating market.
- Loss of working volume as a result of convergence (in high depth).

- High operation cost due to corrosive environment. disposal of the saturated salt water generated during the solution mining process can be costly and environmentally problematic
- Invironment issues related on to brine disposal during construction and operation (Evans and Chadwick, 2009).

2.2.2 Underground storage of natural gas in abandoned mines

Abandoned coal mines have been used to store natural gas and other inert gases since 1961. But it is rarely used due to its limitation. These projects have been set up for meeting peak demands and avoiding the peak pricing of natural gas. Gases mostly can be stored in an abandoned mine through three physical mechanisms: by adsorption on the remaining coal, by solution in the mine water and by compression in the empty space of the mine. For storage natural gas or inert gases in abandoned mines, it is nesseccary to consider the following points:

- There should be no lateral communication with other mines.
- There should be no communication between the mine reservoir and the surface. This would allow the gas to leak to the atmosphere.
- The amount of the influx of water into the mine should preferably be low.
- The top of the mine workings should be at least 500 m underground.
- The reservoir pressure should be 30% more than hydrostatic pressure to prevent water influx (Jalili et al., 2011).

2.2.3 Underground natural gas storage in aquifers

The concept of using aquifers for natural gas storage was first demonstrated in the United States by Louisville Gas and Electric Company with the development of its Doe Run facility in Meade County, Kentucky in 1946 (Evans and Chadwick, 2009). Most of the facilities are located in the Midwestern United States. An aquifer is suitable for gas storage if the water bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be improved by the existence of an active water drive.

In order to develop a natural aquifer into an effective natural gas storage facility, all of the associated infrastructure must also be developed. This includes installation of wells, extraction equipment, pipelines, dehydration facilities, and possibly compression equipment. Since aquifers are naturally full of water, in some instances powerful injection equipment must be used, to allow sufficient injection pressure to push down the resident water and replace it with natural gas. In addition to these considerations, aquifer formations typically require a great deal more cushion gas than do depleted reservoirs. Since there is no naturally occurring gas in the formation to begin with, a certain amount of natural gas that is injected will ultimately prove physically unrecoverable.

In aquifer formations, cushion gas requirements can be as high as 80 percent of the total gas volume. While it is possible to extract cushion gas from depleted reservoirs, doing so from aquifer formations could have negative effects, including formation damage. As such, most of the cushion gas that is injected into any one aquifer formation may remain unrecoverable, even after the storage facility is shut down. Aquifer development can take up to four years, which is more than twice the time it takes to develop depleted reservoirs as storage facilities. In addition to the increased time and cost of aquifer storage, there are also environmental restrictions to using aquifers as natural gas storage. All of these reasons would cause aquifers be expensive to develop, so they are usually only used in areas where there are no depleted gas reservoirs nearby (Bond, 1976; Url-1).

Advantages of underground storage in aquifers:

- High deliverability.
- Can be located near demand centers.

Disadvantages of underground storage in aquifers:

- Usually have water production associated with gas withdrawal, which increases operating costs.
- Reservoir leaks more common as formation seal less certain (aquifers have not trapped oil or gas in the past).
- Requires a relatively large base gas to working gas ratio.
- Lower recovery of the base gas.
- Higher potential for water supply contamination (Url-1; Url-5).

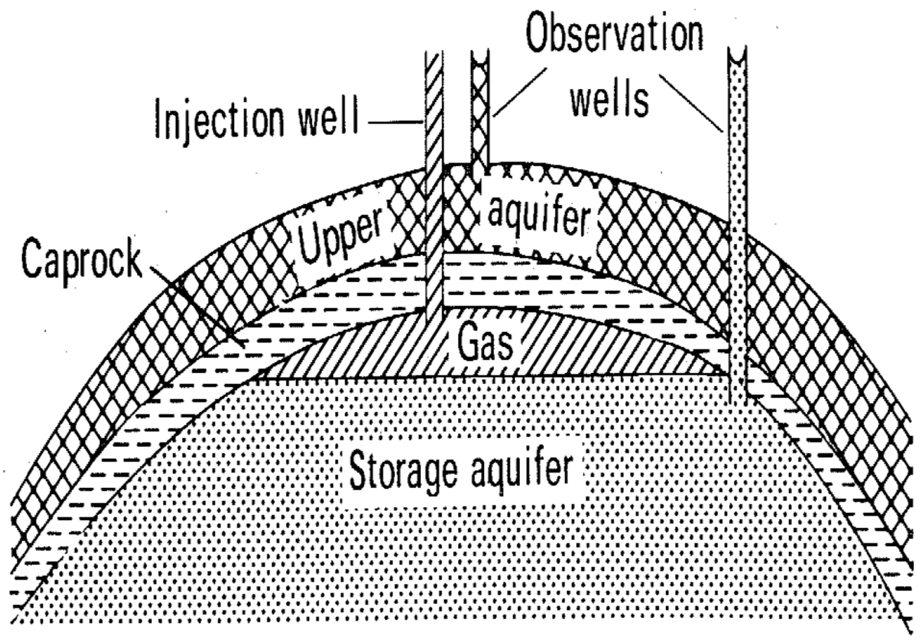

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Figure 2.4: Gas storage in aquifer.

2.2.4 Depleted oil reservoirs

When gas is stored in oil reservoirs, it is generally stored in a gas cap that is already present above the oil in the reservoir; this can be the primary gas cap or a secondary one formed during oil production. The behavior of such an underground gas storage facility is very similar to that of a underground gas storage facility in a gas reservoir. Oil reservoirs without an initial gas cap have also been used for gas storage. Development of full working volume and cushion gas takes many years, since the gas needs to displace the oil, which as a consequence needs to be produced. In these reservoirs the containment of gas requires special attention. In some cases the absence of an initial gas cap may have been caused by a cap rock that is permeable to gas but not to oil. With storage of gas in depleted oil fields, the process may require to deal with two phase flow. Therefore, dry natural gas reservoirs become prime candidates for conversion to storage.

2.2.5 Depleted gas reservoirs

The most ideal underground reservoirs for gas storing gas are the depleted gas fields and also the most underground gas storage facilities are constructed in depleted gas fields. The more ideal reservoir is shallow, high-deliverability depleted gas reservoir.

This is because the characteristic of this reservoir is well known, in term of pressure, capacity and production history. Another reason is that depleted gas reservoirs are capable of storing vast quantities of gas. This provides producers with the ability to be able to meet large demands for a gas during the peak winter season. On the other hand the obvious advantage of depleted gas reservoirs is that the reservoir already has the geological characteristic that is ideal for gas storage. It contains the required porosity and permeability that is favorable for gas storage and an impermeable layer of rock to trap the gas. In addition, the above-ground infrastructure that was originally used to produce gas from the depleted field can also be used to inject and store the gas underground. In simple terms, in order to convert an underground gas reservoir into a storage facility, the existing wells must be refurbished and connected to a compression station in order to maintain the integrity of the reservoir. Once everything such as no leak in cap rock or controlling old wells corrosion, checked and depleted gas field prepared to convert to gas storage field, gas is injected into the reservoir to raise the pressure of the field to the required level for gas to be produced at a desired rate. This gas is called base gas (or cushion gas). After the base gas is injected, the working gas is injected into the reservoirs. The maximum capacity of the underground gas reservoir will be reached when the pressure of the reservoir reaches the original pressure of the production reservoir (Aminian and Mohaghegh, 2009; Evans and Chadwick, 2009). Major considerations with regard to the suitability of a gas field for conversion to underground gas storage are:

1. Containment
2. Size
3. Reservoir properties
4. Well productivity and injectivity
5. Aquifer strength
6. Condensate content of the original gas
7. Distance to existing infrastructure and market

Containment: Although gas reservoirs have proven ability to contain gas on a geological timescale, this does not necessarily mean that when converted to underground gas storage no gas losses will occur. There are several possible reasons for the possible loss of gas:

- overfilling and spilling into a nearby geological structure

- poor cement bonds or casing-related failures in existing wells
- reactivation of faults
- exceeding the capillary threshold entry pressure of the caprock, or even fracturing, when the reservoir pressure is increased above the original reservoir pressure.

Size: The reservoir is limited geologically, and should be large enough to accommodate the working volume and the necessary cushion gas. But it should not be too large; otherwise the amount of required cushion gas becomes too much and may make the project uneconomical.

Reservoir properties: Porosity, permeability and reservoir thickness not only influence the well performance, but are also important for the movement of the gas towards and away from the wells deeper into the reservoir. Gas velocities in underground gas storage reservoir are many times higher than during the original gas production period. Also, a similar volume of gas to that produced over perhaps ten to twenty years during field depletion, may be produced and injected again in periods of just three to six months during underground gas storage.

Well productivity and injectivity: These are strongly dependent on reservoir properties, reservoir depth and tubing size. Although from a purely technical point of view low well productivity does not preclude a reservoir for underground gas storage purposes, the high number of wells required in such a case may make a project uneconomical. For these reasons storage wells tend also to have larger diameter production/injection tubing 7 5\8 " and even 9 5\8 " are now commonly used in the more highly productive reservoirs.

Aquifer strength: Many underground gas storage reservoirs don’t experience significant water flow and behave more or less like a tank, with the reservoir pressure being directly proportional to the amount of gas in the reservoir. However, in same reservoirs, the water that is situated adjacent to, and sometimes beneath the gas-bearing area. In some cases, this flow can be so strong that water will bypass the cushion gas and towards the end of the production season will reach the wells. Gas wells are able to handle limited amounts of water, but too large amounts will kill them.

In several instances it has been observed that when aquifer water reaches the underground gas storage wells, deliverability declines due to the deposition of scale within the wellbores. On the other hand, since the aquifer flow in these cases contributes to maintaining pressure, less cushion gas could be required for this purpose. There is a unstable balance between the amount of cushion gas that is required to prevent too much water reaching the wells and the amount that is sufficient to maintain reservoir pressure at the desired levels.

Condensate content of the original gas: As dry pipeline gas is injected, and comes in contact with the water present in the reservoir, some water evaporates and humidifies the stored gas. Furthermore the injected gas may also come into contact with the original reservoir gas which could contain heavy hydrocarbones that can produce condensates at the surface. Consequently, when gas is withdrawn, it needs to be treated to remove the water and the condensate before it is returned to the transport pipeline system. Removal of both water and condensate requires a different type of gas treatment plant.

Distance to existing infrastructure and market: Since large diameter, high pressure pipelines with sufficient capacity are required to transport the gas to and from the UGS facility, proximity to a main pipeline system can be a major economic consideration. Depleted gas or oil reservoirs depending on their properties have some advantages and also disadvantages. Typically, these kinds of reservoirs are near existing regional pipeline infrastructure. The fields already have a number of useable wells and field gathering facilities which reduces the cost of conversion to gas storage. The geology is well known. These fields have previously trapped hydrocarbons which minimizes the risk of reservoir leaks. Because of the nature of the reservoir producing mechanisms, working gas volumes are usually cycled only once per season.

These reservoirs are old and require a substantial amount of well maintenance and monitoring to ensure working gas is not being lost via wellbore leaks into other permeable reservoirs. Also have lower deliverability than salt caverns and aquifers. On the other hand these reservoirs need high base gas requirements which are almost expensive (Dietert and Pursell, 2000; Pursell, 2006).

2.2.6 Storage inventory

Inventory represents the total volume of natural gas in the storage field at any given time. It represents the sum total of native gas and injected gas. It varies from a minimum value at the end of withdrawal to a maximum value at the end of injection. The total volume in storage is calculated from pressure surveys or the pressure-content performance using volumetric and material balance equations. The gas volumes in storage are classified into two categories:

- Working gas
- Cushion gas (Base gas)

Working gas is the maximum volume of gas available for withdrawal, when the facilities have been completely filled. It varies from season to season depending upon the demand. The working gas volume maybe cycled more than once a year. The amount of working gas is determined by metering gas in and out of the storage reservoir. Its upper limit is defined by the designed maximum pressure for the storage reservoir (Aminian and Mohaghegh, 2009).

Cushion gas is the gas that stays in the underground gas storage. It is not available for withdrawal and stays in the reservoir in order to provide the pressure needed to withdraw the working gas. It is a constant quantity. Deliverability of storage reservoir is one of the most important factors in a design of the pool. The goal of the design is to obtain the maximum storage content with a maximum delivery rate. Both factors are strongly dependent on the cushion gas, meaning that an increase in the cushion gas pressure would result in an increase in the deliverability but decrease in the storage content (Evans and Chadwick, 2009; Tureyen, 2000). Cushion gas itself is considered in two parts as:

Recoverable cushion gas, which is possible to withdraw some of them, after all the working gas produced.

Non-recoverable cushion gas, which is not recoverable because of physical and economic reasons.

The sum of the cushion gas and working gas is called the inventory. The relation between working gas and cushion gas is one of the most important factors in underground gas storage in depleted oil/gas reservoirs.

In order to increase the deliverability rate, depleted gas or oil reservoir require more wells rather than original production wells (Karaalioglu, 1997).

2.3 Inventory Analysis

Inventory analysis or verification is a way to verify amount of gas in the storage field. How much gas will the reservoir hold at the maximum storage pressure and how much could be produced when withdrawing gas down to some base pressure? The objectives of inventory verification include the following:

- To verify that the book inventory is actually present in the reservoir.
- To determine the magnitude of the gas loss (if any).
- To monitor growth (or shrinkage) of the gas bubble in aquifer storage reservoirs.

The basic data used for inventory analysis are shut-in well pressures and volumes of gas metered into (injection) and out of (withdrawal) the field. The two methods for inventory analysis presented include:

- Volumetric Method
- Pressure Decline Curve (Pressure-Content) Method

2.3.1 Volumetric method

In order to make responsible recovery predictions, estimates of the initial gas in place in each reservoir must be made. The volumetric method is a useful tool for calculating the gas in place at any time. The gas storage fields are shut in during turnaround times in spring and fall seasons each year when the supplies and demands are in balance. The shut in period is kept long enough for equalization of the pressure between the wells. Using the shut in pressure for each well and pore volume of reservoir rock containing the gas reserves is determined by geological information based on cores, electric or radioactive logs and drilling records. The standard cubic feet of gas initially in place, G_P, is simply the product of three factors: the reservoir pore volume, the initial gas saturation, and a volume ratio (initial gas formation volume factor) that converts reservoir volumes to volume at standard condition (normally 60 $^{\circ}$F and 14.7 psia). These factors are related as follows:

$$G_p = 43560Ah\emptyset(1 - S_w)\frac{pT_{sc}}{p_{sc}Tz} \quad \textbf{(2.1)}$$

where;

G_P: Gas in place at standard pressure and temperature, SCF

A: Reservoir area, acre

h: Average reservoir thickness, ft

Ø: Average porosity, %

S_w: Average water saturation, %

p: Reservoir Pressure, psi

p_{sc}: Standard pressure, psi

T: Reservoir temperature, ^{0}R

T_{sc}: Standard temperature, ^{0}R

z: Compressibility factor (or gas deviation factor)

This method is used when the production data are not available (Ikoku, 1984).

2.3.2 Pressure decline curve (pressure-content) method

This method involves preparing a plot of the average reservoir pressure divided by gas deviation factor (p/z) against corresponding inventories. For a volumetric (constant volume) reservoir, pressure-content plot is represented by a straight line, which passes through the origin as illustrated in Figure 2.5. The slope of the line is inversely proportional to the pore volume of the gas. In volumetric reservoirs as the inventory changes, p/z remains on the same line.

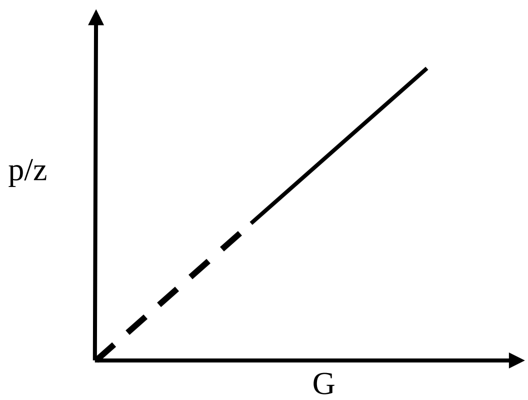

Figure 2.5: Pressure-content curve for a constant volume storage reservoir.

If the storage reservoir has been subject to loss of its inventory, the pressure-content line will be subject to a lateral parallel shift to the right as illustrated in Figure 2.6. The intercept of the line with the inventory axis provides the amounts of the loss.

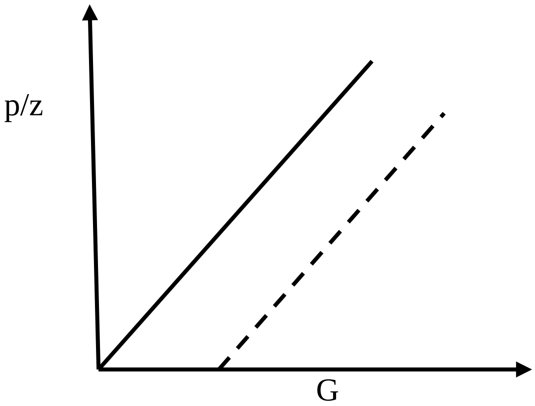

Figure 2.6: Effect of finite gas loss from the reservoir.

Material balances for volumetric gas reservoirs help us to predict working and cushion gas volume as a function of different pressures. A material balance can also help to identify the drive mechanism and the expected recovery factor range, since different drive mechanisms display different pressure behaviors for the same cumulative production as shown in Figure 2.7 (Mireault and Dean, 2008).

If water is encroaching, the reservoir hydrocarbon volume is not constant with time; consequently, a plot of p/z vs. G_p is not a straight line. The water drive reservoir plots as a curve that is concave upward (the blue line in Figure 2.7). Because of water influx, the pressure drops less rapidly with production than under volumetric control. Material balance is simply an expression of the law of conversion of mass. Equation below is simplest form of the material balance equation.

$$\frac{p}{z} = \frac{p_i}{z_i} - \frac{p_i}{z_i G_i} G_p \qquad \textbf{(2.2)}$$

where;

p: Pressure at any time, psia

p_i: Initial pressure, psia

z: z at any time

z_i: z at initial pressure

G_p: Cumulative gas production at any time, sm^3

G_i: Cumulative gas production at initial pressure, sm^3

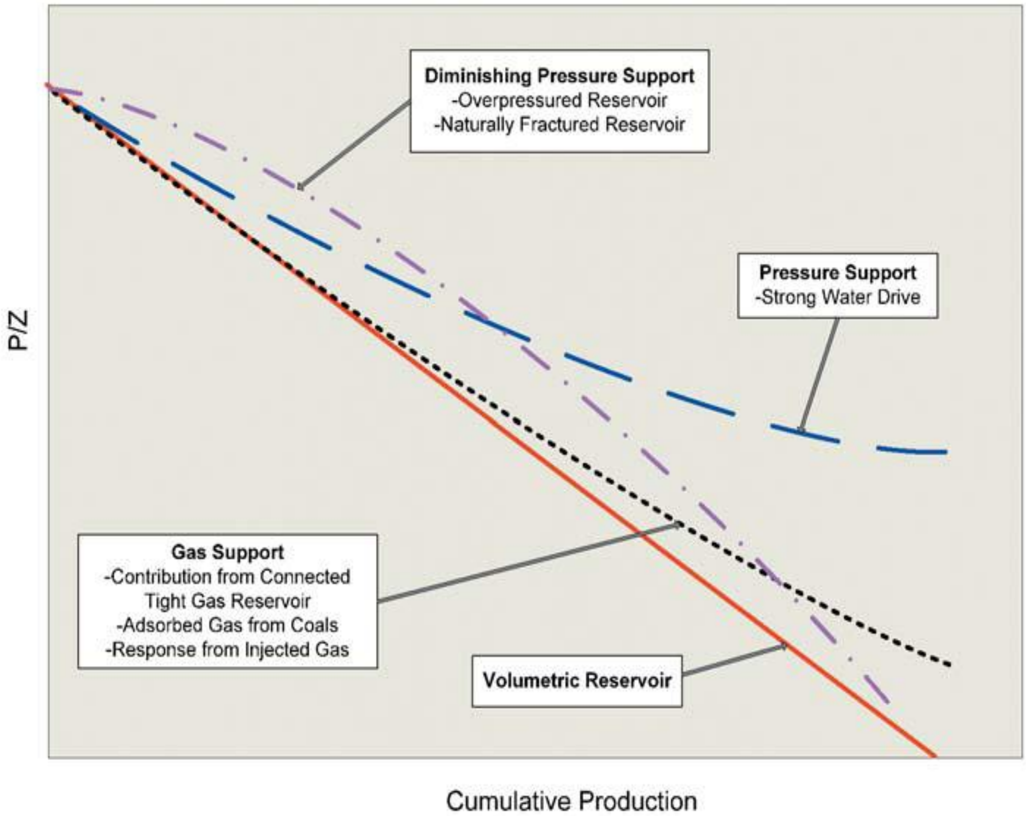

Figure 2.7: Gas reservoir p/z material balance diagnostics (Mireault and Dean, 2008).

$$m = -\,{}^{p_i}/_{(z_i G_i)} \qquad \textbf{(2.3)}$$

Where;

m: slope of the curve.

The gas in place can be calculated using Equation 2.4 derived from Equation 2.2.

$$G_i = \frac{{}^{p_i}/_{z_i}}{\left[{}^{p_i}/_{z_i G_i}\right]} \qquad \textbf{(2.4)}$$

Equation 2.2 is correct when reservoir is without any water influx and no large pressure gradient exists across the reservoir. Natural gas reservoirs generally are found at discovery pressure gradient 0.2 to 0.52 psi/ft (4.5 to 11.76 Kpa/m), while the pressure gradient due to the weight of overburden is about 1 psi/ft (22.6 Kpa/m) (Url-3). The range of delta pressures (top gas storage pressure-discovry pressure) used in gas storage reservoirs to expand the working gas volume. Notice that the top gas storage pressure should be less than fractured pressure.

Figure 2.8 shows pressure-production graph.

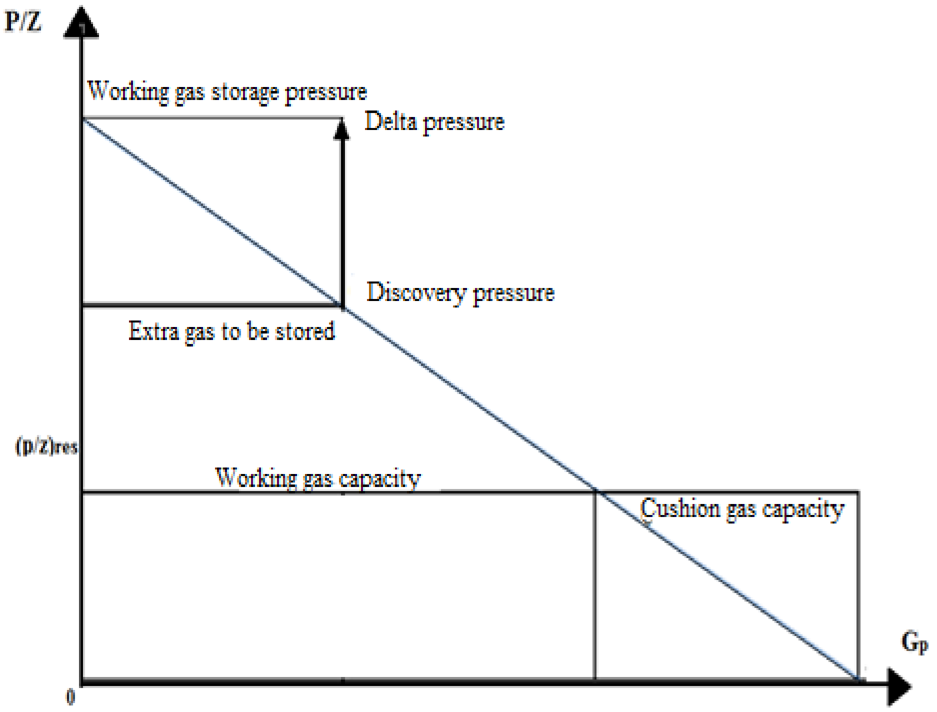

Figure 2.8: Pressure-production graph with extended pressure limits.

2.4 History and Growth of Underground Storage in the World

Underground natural gas storage fields grew in popularity shortly after World War II. At the time, the natural gas industry noted that seasonal demand increases could not feasibly be met by pipeline delivery alone. In order to meet seasonal demand increases, the deliverability of pipelines (and thus their size), would have to increase dramatically. However, the technology required to construct such large pipelines to consuming regions was, at the time, unattainable and unfeasible. In order to be able to meet seasonal demand increases, underground storage fields were the only option. The first instance of natural gas successfully being stored underground occurred in Weland County, Ontario, Canada, in 1915 (Evans and Chadwick, 2009). This storage facility used a depleted natural gas well that had been reconditioned into a storage field. In the United States, the first storage facility was developed just south of Buffalo, New York, which was second attempt in the world. This field is still in use as a UGS facility after 90 years of service. Gradually more and more gas fields in the USA were converted to UGS. By 1930, there were nine storage facilities in six different states. In 1942 the first oilfield, Playa del Rey, California, was converted to storage. In the next ten years, number of pools increase rapidly and doubled to 178 pools with a capacity of 1849 billion SCF. The rapid increase in UGS started to slow down in 1990. Figure 2.9 shows the locations and types of UGS pools in the USA. Prior to 1950, virtually all natural gas storage facilities were in depleted reservoirs.

In some areas, mostly in the Midwestern US, natural aquifers have been converted to gas storage reservoirs. In 1946 in Kentucky, the first storage in an aquifer was created. In Europe, gas storage started in Germany in 1953 in the Engelborstel aquifer storage.

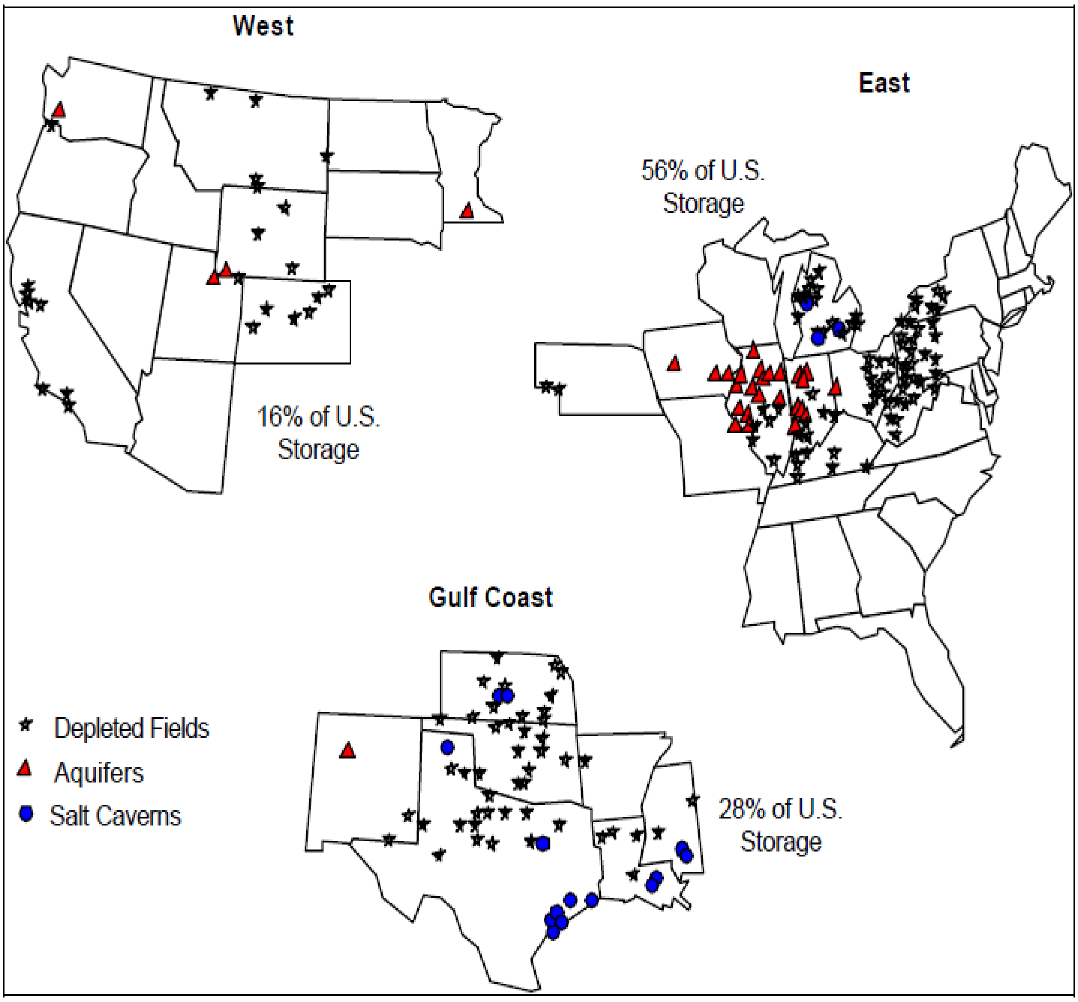

Figure 2.9: Regional underground natural gas storage facilities in USA.

A third and very common formation used in gas storage is salt caverns. Gas storage in salt caverns is a more recent development. The first UGS salt cavern was commissioned in 1961 in Michigan (USA), followed by the first facility in Canada in 1964, and in Europe in 1970 (Tersanne, France). The large majority of salt cavern storage facilities have been developed in salt dome formations located in the Gulf Coast States. By early 2007 there were 628 UGS facilities operational worldwide, with a total working volume of 318 $\times 10^9$ m3 and a deliverability of 5.4 $\times 10^9$ m3/day. Most of these (390) are located in the USA. Table 2.1 gives an overview of UGS by area (Evans and Chadwick, 2009; Han et al., 2006).

Table 2.1: Overview on underground gas storage facilities by area (Evans and Chadwick, 2009).

Area	Number of underground gas storage facilities					Working volume (10^9 m^3)	Deliverability (10^6 m^3/d)
	Gas & oil field	Aquifer	Salt cavern	Others	Total		
Europe	68	23	29	3	123	79	1560
Former Soviet Union	36	13	1	-	50	109	980
USA	318	45	26	1	390	108	2560
Canada	45	-	9	-	54	20	315
South America	2	-	-	-	2	0.2	2
Asia	5	-	-	-	5	1.6	11
Australia	4	-	-	-	4	1.0	10
Total	478	81	65	4	628	318	5440

3. PARAMETERS AFFECTING UNDERGROUND GAS STORAGE

In this section, the most effective factors influencing the different aspects of the underground gas storage are described. These factors can affect properties and conditions of the storage modeling in different ways.

3.1 Effective Factors in Underground Natural Gas Modelling

The most common type of underground storage is storage in depleted gas reservoirs. Considering this fact, the geology of depleted storage reservoirs are well known as they have been producing gas before being used for storage purposes. As mentioned before this type of storing has some significant and important advantages. These reservoirs geologically are capable of holding natural gas. It is necessary to prove that the gas to be stored there will not escape and therefore ensure the cap rock's continuity and the closure. Certifying whether a structure can be used for storage purposes is a complex and costly operation. In addition, the use of depleted reservoir for storage purposes allows the use of the equipment left over from when the field was productive and using these equipment helps to reduce cost. Depleted reservoirs are also attractive because their geological characteristics are already well known. Of the three types of underground storage, depleted reservoirs, on average, are the cheapest and easiest to develop, operate, and maintain.

The factors that determine whether a depleted reservoir will make a suitable storage facility are both geographic and geologic. Geographically, depleted reservoirs must be relatively close to consuming regions and transportation infrastructure and distribution systems. Geologically, depleted reservoir formations must have high permeability and porosity. The most important parameters to take in consideration are (Flanigan, 1995):

- reservoir capacity
- maximum reservoir pressure
- number of wells

- wellhead pressure
- working gas to cushion gas ratio.

The additional parameters that effect the performance of the field are formation characteristics related to geology. When converting a gas field to storage, the following factors need to be considered (Katz and Lee, 1981):

- Gathering geological and engineering information
- Investigation of well conditions
- Determining working storage content
- Determining the required well
- Considering compression, field lines and gas condition.

First step is gathering information on the field, such as the following:

- Initial reservoir pressure
- Reservoir temperature
- Gas production versus reservoir pressure
- Gas gravity
- Wells location, depth and core data
- Isopach map
- Degree of water drive
- Logs on well
- Well flow capacity
- Mechanical condition of wells.

After gathering some geological information, the next step is well revision against leaks and well corrosion. These wells have been produced for a long time in production period. In order to solve these problems, squeezed cement or packers could be used against corrosion within producing zone. In addition, cap rock properties should be studied with core analysis, logs and various tests to ensure of no leak. After evaluating well conditions and cap rock, the top pressure (pressure when reservoir has its maximum content) can be determined.

In underground gas storage fields, the goal is to maximize top pressure to increase working gas capacity. In some reservoirs, when caprock is thin or there is not enough overburden pressure or because of some undesired environmental situation, the discovery pressure is used as the top pressure, increasing the pressure may cause fracturing of caprocks and cause leakage.

The use of pressure above discovery pressure, a delta pressure, gives added usage for given reservoir. The next step is determining working gas capacity. If p/z versus production plot of the gas reservoir is available, then storage capacity of the reservoir can be calculated by placing top pressure and base pressure values on the plot. If the reservoir is abnormally pressured or is under water drive, it will show on the p/z versus production plot. The next step is determining required wells. With due attention to this fact that 80 to 100 percent of initial gas content in a storage reservoir will be withdrawn within very short periods, additional new wells should be drilled for rising gas deliverability due to peak demand. Determination of new well locations and well numbers are the important issues to consider. The other point to consider is the cost of drilling new wells. The largest cost item in the storage is usually the compressor installation. Compressor provides pressure rise necessary to work against the various pressure drop. In some cases, additional wells may be added in order to reduce the compressor horsepower and total cost (Flanigan, 1995; Katz and Lee, 1981; Tureyen, 2000).

3.2 Types of Modelling

An underground storage system contains several subsystems such as; the well casing, gathering system, purification facilities (to remove condensates and etc.) and compression facilities. The optimum design is the best combination of these subsystems. The variables subject to optimizing a gas storage field are (Van Horn and Wienecke, 1970):

- The volume of gas in storage field
- Number of wells
- Producing rate of the wells
- Line pressure
- Size of casing
- Formation characteristics

Size of compression equipment used for a withdrawal storage field is developed by locating an appropriate reservoir and drilling wells to convert the reservoir to a gas storage field. In depleted gas reservoirs when the amount of non-recoverable gas is not enough, gas is injected into the reservoir until reservoir contains the sufficient volume of gas (cushion gas) to be used for storage. The ability of wells to produce gas depends on pressure which is a function of injected gas into the reservoir. Also the wells ability to produce is increased by using large casing. The total gas available from fields depends on the number of wells as well as producing rate of the wells. Then equipment must be selected for transporting gas from wells to pipeline and deliver to transmission system. Maximizing working gas volume, maximizing the peak rate load or minimizing the cost to satisfy specific production and injection schedules are the most critical parameters which are considered in designing the conversion of producing field to storage. Optimization of gas storage field development and maximizing withdrawal rate has been investigated by several researchers. Some performed investigations are discussed below.

Henderson et. al. (1968) used two-dimensional single phase dry gas simulator for optimizing gas storage field. They varied the well location to increase withdrawal rate for peak demands. They used trial and error method. They conclude that wells located in poorest section of field could help to meet demand at the beginning of withdrawal period. Additional wells were added over time to increase withdrawal rate. The wells located in the best part of reservoir were held in reserve to meet the peak day needs at the end of withdrawal season.

Duane (1967) presented a graphical technique for optimizing gas storage design on the basis of minimizing the total field development cost for designing the peak-day rate and working gas capacity. In this method a series of field-design optimization graphs for different compressor intake pressures are prepared. Each graph consists of series of curves corresponding to peak-day rates. Each curve shows the number of wells which is required to deliver the given peak-day rate. So the trade off between compression horsepower costs, well costs, and cushion gas costs could be examined to determine the optimum design in terms of minimizing the total field-development cost. This operation of optimization has been computerized now and data for both field design optimization graphs and final field design-total cost graphs will be generated directly from the basic field input data by the computer.

There is another study in optimizing gas storage field presented by Coats (1969). He used a two dimensional numerical method of semi-steady-state flow for locating new wells in a heterogeneous field. His object was to determine the optimum drilling program to maintain a wanted deliverability during field development. He provides a discussion of whether wells should be located closer together in areas of high kh or of low kh. The method used in this study, minimizes new well requirements at each successive stage of depletion by selecting optimal locations for additional wells. The method accounts for the effects on well deliverability of reservoirs heterogeneity and unequal spacing of wells. Two cases were run for the field. First was with 27 wells spread over field but concentrated in high permeability portion. The second was the same 27 wells concentrated in low permeability portion. The results showed that if Øh is approximately constant and kh values varied due to variation in k, then the wells should be located closer together in low kh area. The similar calculation was repeated to investigate the variation of Øh distribution. In this case, uniform permeability and porosity were assumed for a given field where thickness varying from northwest to southeast. Again in first case, 27 wells with same properties are located close to each other in high kh portion and in second case 27 wells concentrated in lower kh portion and results showed that if porosity is highly correlated with permeability, wells should be closer together in areas of high kh.

Karaalioglu (1997) studied the modelling of the Northern Marmara field as an underground gas storage reservoir. This study was based on two approaches. The first modelling approach was to determine the minimum number of wells for known base and working capacities and the known withdrawal/injection rate and periods. In the second modelling approach, maximizing of working gas volume and peak rates for a particular configuration of reservoir, well and surface facilities, number of wells and production/injection periods are studied. The study should that modelling a gas reservoir for underground gas storage purpose requires an optimization approach correlating and combining the effects of fluid, rock, well and other operation parameters. Also in order to operate the Northern Marmara gas field as a storage reservoir with respectable working gas capacity ($\geq 1\times10^9$ Sm^3), the required number of vertical wells varies between 20 and 50 depending on desired wellhead pressure.

Due to critical importance of natural gas storage in Turkey, Tureyen (2000) has conducted a study of modelling Northern Marmara field for storage purpose. In this study maximizing the working gas capacity of the field for a given number of wells and well properties is investigated. The reservoir performance was modelled by using material balance graphs. For maximizing the working gas capacity of the reservoir the optimization method proposed by McVay and Spivey (1994) is used in this study. The result of this study indicated that the wellhead pressure has significant effects on the performance of the underground storage reservoir. In addition, it is inferred that the number of horizontal wells required to obtain desire working gas capacity strongly depends on the wellbore damage conditions of the wells, the horizontal length and partial completion characteristics.

4. DESIGN CRITERIA CONSIDERED FOR THE X GAS FIELD

In this section, the criteria used in this modeling study are presented. Two criteria are considered.

- Determining the minimum number of wells due to peak day requirement
- Determining the minimum number of wells based on minimum and maximum pressure constraints on wellhead pressures for production and injection periods.

Before presenting the design criteria and the related results, an over view of the properties at the X gas field and its RUBIS model is presented first. The determination of the RUBIS black oil simulation is given in the Appendix A.

4.1 The Properties of X Gas Field

The X field is a hypothetical dry gas reservoir. It is assumed that the properties of the X gas field and the northern Marmara field are similar. The initial pressure of the reservoir is 2068 psia with a temperature of 155 °F. The pressure of reservoir dropped to 1305 psia, after producing 1970 million Sm^3. This field is to be converted to a gas storage field.

The depth of the reservoir is 1200 m (3937 ft). The porosity and average water saturation of the reservoir rock are 0.15 and 10%, respectively. The average permeability is 25 md with an anisotropy ratio of 0.7 between the horizontal and vertical permeabilities (k_v/k_h = 0.7). The reservoir average thickness is 60 m. The reservoir area is around 6.25 km^2. The gas specific gravity is 0.58. The gas in place has been estimated to be 5.1 billion Sm^3. The p/z versus Q_g (cumulative gas production) plot is obtained by using the production data of the field. The p/z versus Q_g plot is given in Figure 4.1. The cap rock formation thickness is 10-60 meter. The gas composition is shown in Table 4.1.

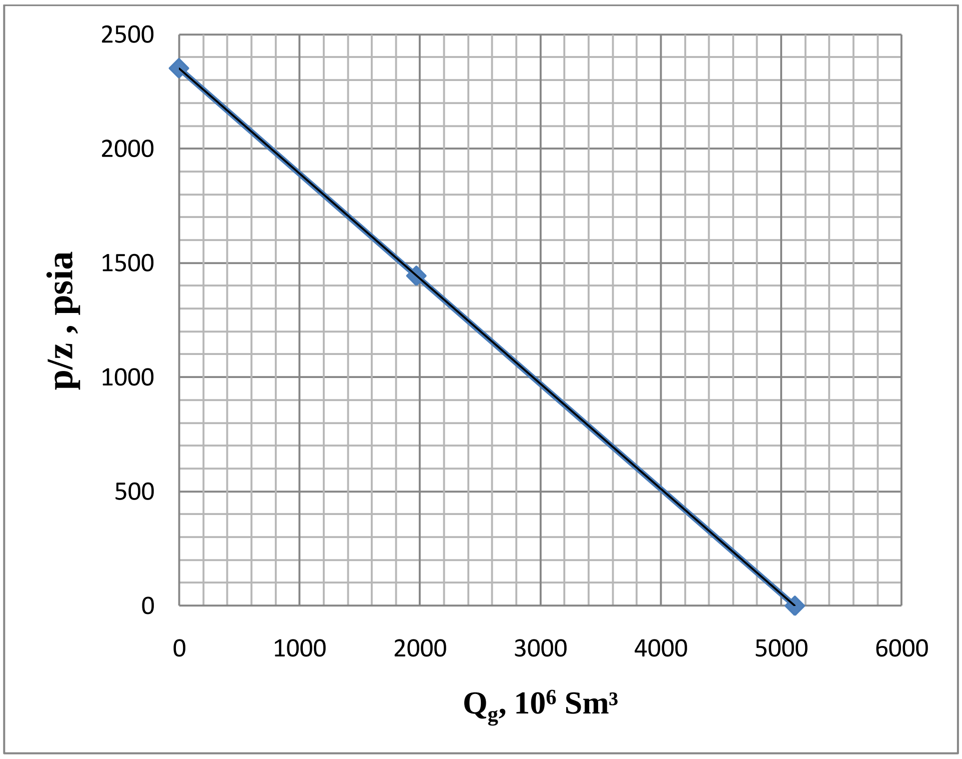

Figure 4.1: The p/z versus cumulative gas production plot.

Table 4.1: The gas composition of X field.

Gas Compositions	Mole %
C_1	95.52
C_2	2.41
C_3	0.74
i-C_4	0.17
n-C_4	0.20
i-C_5	0.09
n-C_5	0.08
N_2	0.78
CO_2	0.01

4.2 The RUBIS Model for X Gas Field

The objective of this study is to investigate the number of wells that are required to convert the X gas field to a storage reservoir. In this study, the X gas field is modeled by the RUBIS software. A three dimensional, one phase (dry gas) numerical model is used to simulate the injection and production behavior. The reservoir is represented using a grid system consisting of a total of approximately 2000 blocks. The thickness of the reservoir is represented with 5 blocks. Figure 4.2 shows the reservoir 3D shape.

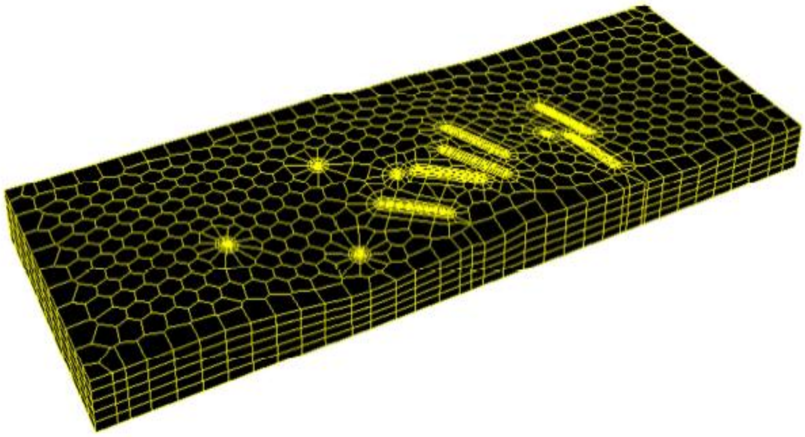

Figure 4.2: 3D geometry plot of X reservoir.

In beginning of using RUBIS software, the simulation interval is selected. Then in the part of PVT definition, the type of reservoir hydrocarbon has been defined as dry gas including no water and no condensate. The reservoir 2D shape is selected as a rectangle where, L_x= 3537 m and L_y=1768 m. The 2D geometry of reservoir is given in Figure 4.3.

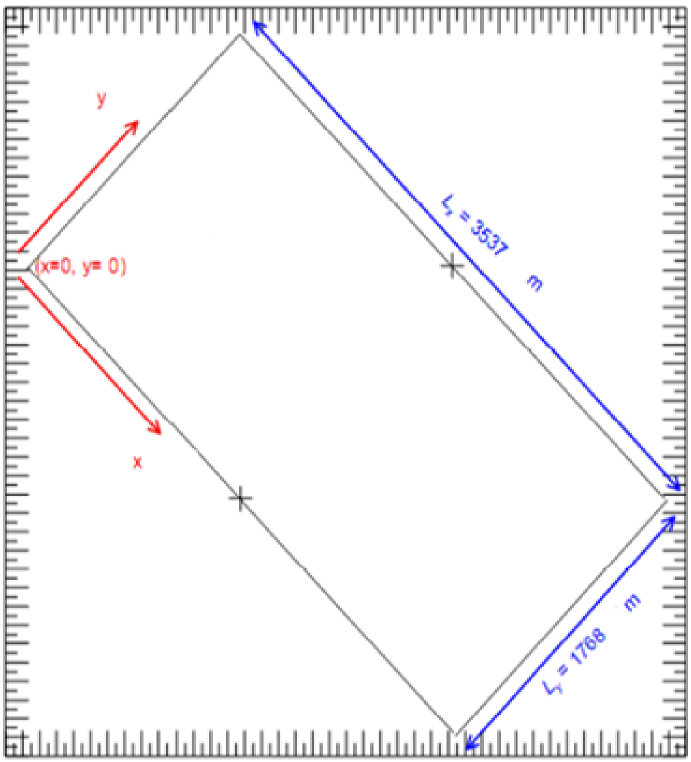

Figure 4.3: Rectangle's model of X field reservoir.

The same gas composition as that given in Table 4.1 is used in RUBIS. For computing the gas deviation factor the Abu-kassem method is used (Lee and Wattenbarger, 1996). For the viscosity, the correlations provided by Lee and Wattenbarger (1996) are used. The overall topology of the field can be seen in Figure 4.4.

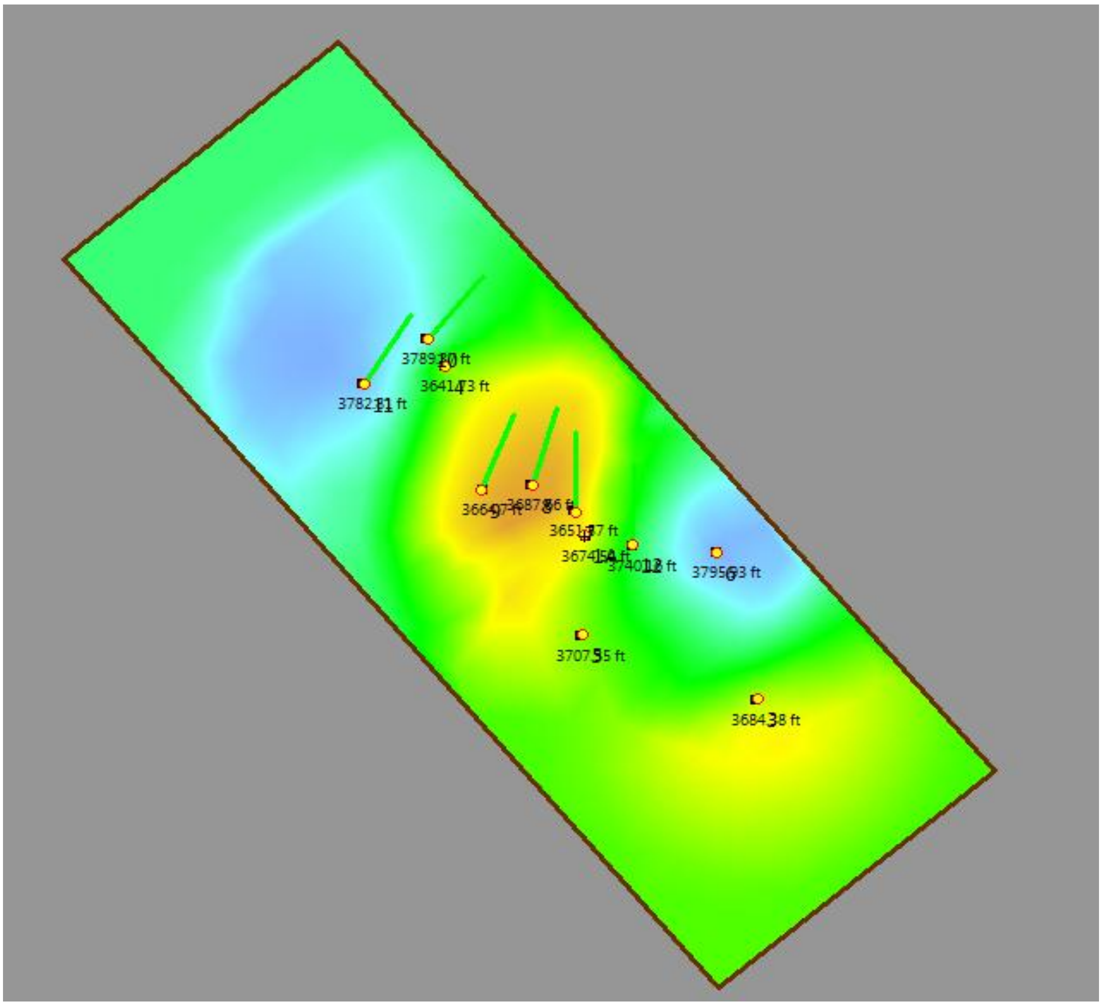

Figure 4.4: Topology of the field using interpolation method.

The relationship between p/z and cumulative gas production results from RUBIS program are obtained. Figure 4.5 clearly illustrates that the RUBIS model material balance behavior is consistant with that of the data provided in Figure 4.1.

In the following two subsections, the RUBIS model will be used to determine the number of wells required to meet certain criteria. In the first criteria the number of wells will be determined based on meeting peak day requirements. In the second criteria the number of the wells will be determined based on meeting certain pressure constraints.

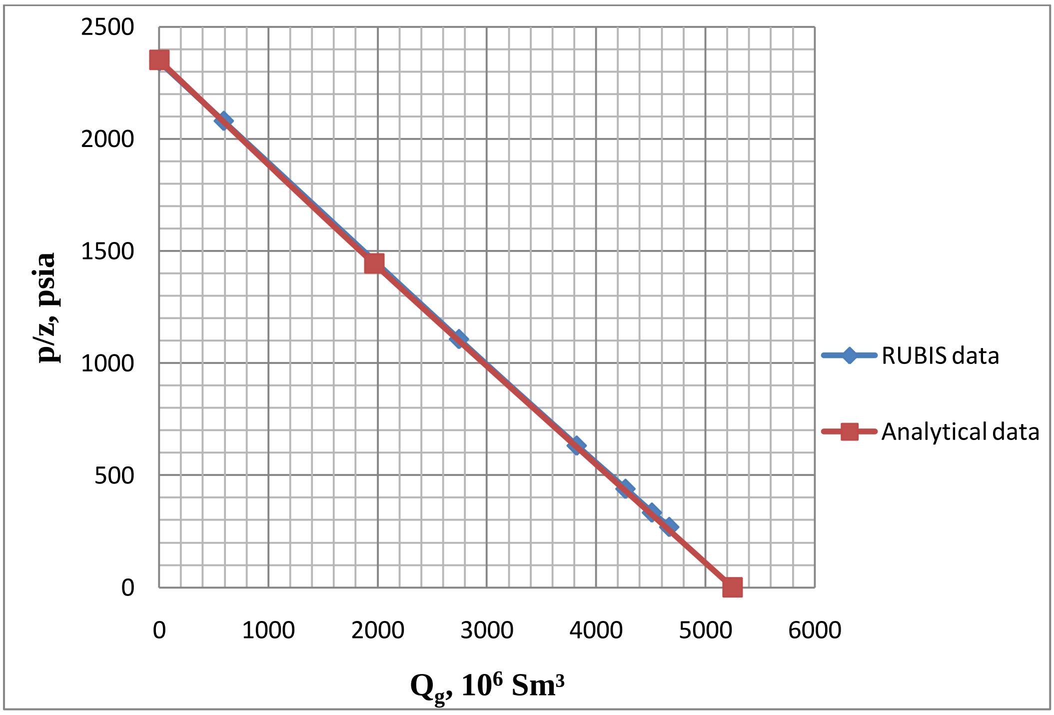

Figure 4.5: p/z versus Q_g plot.

Finally to check the accuracy of the RUBIS model, the data in both RUBIS model and analytical method are compared.

4.3 Criteria Based on Meeting Peak Day Requirements

In this section, the required number of wells is determined for a criterion such that a total daily flow rate of 1/40 of the working gas content must be satisfied after 75% of the working gas has been removed. All the computations involved using this criteria is applied only to the withdrawal period. The reason for this, as discussed below, the deliverability equation (Eq. 4.1) is assumed to only present the withdrawal period. Thus the number of wells required is obtained from the design calculation should be the adequate number of wells for the withdrawal period but not the injection period. Furthermore the criteria involving peak day requirements contain only the withdrawal period.

Aside from using the RUBIS software we have also considered an analytical approach to determine the total number wells required. In the analytical approach the reservoir behavior is modelled by the well known Rawlins and Schellhardt (1935) equation (Eq 4.1) in terms of well head static and flowing pressures.

$$q = C(p_{whs}{}^2 - p_{whf}{}^2)^n \qquad \textbf{(4.1)}$$

where;

q: Flow rate, MMscf/D

p_{whs}: Wellhead static pressure, psia

p_{whf}: Wellhead flowing pressure, psia

C: Stabilized performance coefficient, MMscf/D/psia^{2n}

n: Turbulence factor.

For this problem at hand the constants in the equation are calculated and the related deliverability equation is exposed as q= 0.0388 (p_{whs}^2-p_{whf}^2) $^{0.548}$. The top pressure for the storage reservoir is 2014.7 psia and the base gas pressure is reported to be 1214.7 psia. Based on the two limits the working gas capacity is computed as 2.07×10^9 Sm^3 from Figure 4.1.

When 75% of the working gas is produced, 517.9×10^6 Sm^3 of gas still remains to be produced during the production period. The reservoir pressure at this point is computed as 1418 psia.

Using the average temperature and z-factor method given by Lee and Wattenbarger (1996) in Equation 4.2, we compute the static wellhead pressure. Then for various flowing well head pressures, the total number of wells required can be computed that will meet a total daily flow rate of 51.8 ×10^6 Sm^3/D which is 1/40 of the working gas capacity.

$$p_{ws} = p_{whs} \exp\left(\frac{0.01875\gamma_g L}{\overline{T}\overline{z}}\right) \qquad \textbf{(4.2)}$$

where;

p_{ws} : Bottomhole static pressure, psia

p_{whs} : Wellhead static pressure, psia

L : Depth of the well, ft

γ_g: Specific gas gravity

When using the RUBIS software, the model is initialized at the pressure when 75% of the working gas capacity is produced and different number of wells are tried to meet a total production rate of 1/40 of the working gas content. The number of wells has been determined for various scenarios using the RUBIS software. These include, cases for various well head pressures, cases where 60% of working gas capacity is produced, or 90% of working gas capacity is produced, cases for various skin factors and tubing diameters. In one of the cases, the result of the analytical approach is also given for comparison purposes.

4.3.1 Effect of wellhead flowing pressure on the number of wells required

The purpose here is to determine the number of wells such that the field would be able to produce at maximum flow rate capacity (1/40 of working gas capacity) when 75 percent of working gas content is produced. At the beginning of withdrawal period, the reservoir has adequate amount of pressure to support high flow rates for deliverability. But after a certain amount of gas is produced, the average reservoir pressure decreases. In that case, the design of storage field should be prepared such that it can deliver the demand of the market at the end of the withdrawal period. The results are given in Table 4.2. It is important to note that all wells considered here are vertical wells.

Table 4.2: Number of wells for various wellhead flowing pressures, after removing 75% of working gas content.

Wellhead flowing pressure, bar	Number of wells (RUBIS model)	Number of wells (using the deliverability equation)
46	21	22
50	22	23
52	23	23
55	23	24
57	25	24
60	27	25
65	30	27
70	35	30

As seen in Table 4.2, it is shown that 35 wells are required to produce maximum peak day requirement when the wellhead flowing pressure is 70 bars. When minimum wellhead pressure of 46 bar is used, the required number of wells is 21 under the assumption that all wells have the same wellbore and flow characteristics. The wellbore inside diameter considered here is 7 inch for all wells. The important point to consider is that decreasing in wellhead pressure results in a fewer number of wells to maintain the flow rate.

The same procedure is applied for calculating well numbers, when 60 % and 90 % of working gas volume are removed from X storage field. Table 4.3 summarizes the results. A comparison of the required number of wells to obtain peak day requirements for three different conditions are given in a Table 4.3.

Table 4.3: Comparison of the required number of wells for 60, 75 and 90% removed gas capacity.

Wellhead flowing pressure, bar	Required number of wells when 90% of WGC is produced	Required number of wells when 75% of WGC is produced	Required number of wells when 60% of WGC is produced
46	26	21	18
50	27	22	19
52	28	23	19
55	30	23	19
57	32	25	21
60	35	27	21
65	43	30	24
70	56	35	26

As expected when the produced amount of working volume increases the number of the wells increases as well. This is because when more gas is produced, the pressure is decreased hence more wells become necessary for the same deliverability.

4.3.2 Effect of skin factor on the number of wells required

Efforts to minimize wellbore damage help to improve the production/injection performance of the storage reservoirs. In this modelling study, the effects of skin factor on the required number of wells to meet the flow rate criteria, after producing 75 percent of working gas capacity at the constant wellhead flowing pressure of 50 bars in vertical wells, is studied. The results are given in Table 4.4.

As expected the increase in the skin factor results in a decrease in deliverability which causes the number of the wells required to increase.

Table 4.4: Effect of skin factor on number of wells required.

Skin	Required number of wells
-2	17
0	22
5	35
10	49
20	76

As expected, the decreases in skin factor due to stimulation results in decreases in the number of wells.

4.3.3 Effect of horizontal length of horizontal wells on the total number of wells required

The effect of horizontal length of horizontal wells in modeling of X reservoir field is studied under the assumption of a wellhead flowing pressure of 50 bars. The wellbore conditions are the same for all wells and tubing diameter is 7 inch. The results are presented in Table 4.5.

Table 4.5: Effect of the horizontal well length on the number of wells required.

Horizontal length, ft	Number of wells required
250	18
300	13
500	13
700	12
900	11
1100	11
1300	10

As expected the number of the wells decreases when the horizontal length increases. As shown in Table 4.5 for a horizontal well length of 250 feet, 18 wells are needed. When the well length increases to 1300 ft, the required wells number decreases to 10.

4.4 Criteria based on the wellhead flowing pressure constraints

Here the required number of wells is determined by given constraints on flowing wellhead pressure. In this case, the production and the injection periods are treated separately. During the production period the number of wells is determined such that the flowing wellhead pressures do not decrease below a certain limit. This limit is based on compressor characteristics. During the injection period, the total number of wells is determined such that the flowing wellhead pressures do not exceed a certain maximum limit. Two factors determine this limit. The first factor is compressor limit and the second factor is the fracturing pressure of the reservoir. During the production period a lower pressure limit of 1214.7 psia is used. During the injection period an upper pressure limit of 2014.7 psia is used. The withdrawal and injection periods are assumed to be 150 days.

Once again we use two approaches for modeling the reservoir. In the first approach we use an analytical model and in the second approach we use RUBIS. When using the analytical approach we use two of the theoretical approaches used in the literature for modeling the behavior of vertical and horizontal wells. The relationship for vertical well is given in Equation 4.3.

$$q = \frac{0.703kh(\bar{p}^2 - p_{wf}{}^2)}{T\bar{\mu}\bar{z}(\ln(r_e/r_w) - 0.75 + S_m + Dq)} \quad \textbf{(4.3)}$$

where;

q: Flow rate, scf/D

k_a: Reservoir mean permeability, md

h: Reservoir thickness, ft

p_{wf}: Reservoir bottomhole pressure, psia

T: Reservoir temperature, ^oR

r_e: Drainage area, ft

r_w: Tubing radius, ft

S_m: Mechanical skin factor

D: Non Darcy flow constant, D/scf.

The non Darcy flow constant term for vertical wells can be approximated using Equations 4.4 and 4.5.

$$D = 2.222 \times 10^{-18} \frac{k_a \gamma h \beta}{\mu {h_p}^2 r_w} \quad \textbf{(4.4)}$$

where;

$$\beta = \frac{4.851 \times 10^4}{\emptyset^{5.5}\sqrt{k}} \quad \textbf{(4.5)}$$

Ø: Reservoir porosity

µ: Reservoir viscosity, cp

γ: Gas specific gravity

ß: Turbulence factor, ft^{-1}

h_p: Length of producing interval, ft

The inflow performance relationship for horizontal well for pseudo steady state flow is given by Equation 4.6 (Thomas et al., 1998).

$$q = \frac{0.703\ kh\left(\overline{P}^2 - {P_{wf}}^2\right)}{T\overline{\mu}\overline{z}(\ln(r_e/r_w) - 0.75 + S + S_{CA} - C' + (\sqrt{k_x}h/\sqrt{k_z}L)(S_m + Dq)} \qquad \textbf{(4.6)}$$

where;

S_{CA}: shape factor related skin factor

C': shape factor conversion constant, 1.386

S: Equivalent negative skin factor

The non Darcy flow constant term for horizontal wells can be approximated using Equation 4.7.

$$D = 2.222 \times 10^{-18} \frac{k_a \gamma L \beta}{\mu {L_p}^2 r_w} \qquad \textbf{(4.7)}$$

S value may be approximated by using equation 4.8.

$$S = -\ln\left(\frac{r'_w}{r_w}\right) \qquad \textbf{(4.8)}$$

where;

$$r'_w = \frac{L}{4} \qquad \textbf{(4.9)}$$

L: Length of horizontal wells, ft.

The S_{CA} value represents the shape factor related skin factor. In order to be simplified, the drainage area for all horizontal wells has been considered as a square in this study. S_{CA} value in horizontal wells for square drainage areas depends on well length. Drainage areas are given in Table 4.6.

($L/2X_e$) in Table 4.6 represents the ratio of the horizontal well length to the length of the side of the drainage area parallel to the horizontal well. The L_D values in Table 4.6 can be determined by Equation 4.10.

$$L_D = \left(\frac{L}{2h}\right)\sqrt{\frac{k_v}{k_h}} \qquad \textbf{(4.10)}$$

The IPR equations are used to represent the reservoir performance of horizontal wells. Also the wellbore performance is determined by using the exponential method given by Eqs 4.11 and 4.12:

Table 4.6: S_{CA} values for square shaped drainage areas.

	(L/2X_e)				
L_D	0.2	0.4	0.6	0.8	1
1	3.772	4.439	4.557	4.819	5.250
2	2.321	2.732	2.927	3.141	3.354
3	1.983	2.240	2.437	2.626	2.832
5	1.724	1.891	1.948	2.125	2.356
10	1.536	1.644	1.703	1.851	2.061
20	1.452	1.526	1.598	1.733	1.930
50	1.420	1.471	1.546	1.672	1.863
100	1.412	1.458	1.533	1.656	1.845

$$p^2{}_{wf} - e^s p^2{}_{tf} = \pm \frac{6.67 \times 10^{-4} (q\overline{T}\overline{Z})^2 (e^s - 1) f_m}{d^5} \tag{4.11}$$

where;

$$s = \frac{0.0375 \gamma_g L}{\overline{T}\overline{Z}} \tag{4.12}$$

p_{wf}: Flowing bottomhole pressure, psia

p_{tf}: Flowing tubing wellhead pressure, psia

q: Flow rate, Mscf/D

f_m: Moody friction factor

d: Tubing inside diameter, inch

L: Depth of well, ft.

In the design of X gas storage reservoir using pressure constraints, suggested procedure is described below.

Assuming that the flow rate is kept constant in the injection and withdrawal periods then the flow rate calculated for 150 days of both injection and withdrawal periods as 13.8×10^6 Sm^3/D (487.696 MMScf/D). Both the theoretical equations and RUBIS have been used to determine the number of wells for the given pressure constraints. The procedure starts with a random number of wells. Then the model is run either for the injection or the production period. During the run the wellhead pressures are observed. If at any time the constraints are violated, then it is concluded that the selected number of wells are not enough and that it should be increased. Then the number of wells is increased by one and the procedure is repeated until all pressure constraints are honored throughout the entire run. Once the pressure constraints are honored then the number of wells is recorded as the optimum number of wells. If at the start, all constraints are honored, then the number of wells decreased by one and the procedure is repeated. Until the wells fail to meet the constraint, then the minimum number of wells that meet the constraint is assigned to be the optimal number of wells.

Table 4.7 gives a comparison for the number of wells to be used. Based on the RUBIS model a minimum of 12 vertical wells are necessary for the production period and 16 vertical wells are necessary for the injection period. Based on using RUBIS as the reservoir model, a minimum of 16 vertical wells are necessary to honor all constraints on pressures.

If horizontal wells having horizontal length of 300 meter are used, then a minimum of 6 horizontal wells are required during the production period and 6 horizontal wells are required during the injection periods. Hence it is concluded that 6 horizontal wells are necessary to meet all constraints. It is important to note that for both horizontal and vertical wells, the determination of the required number of wells is dominated by the injection period.

When the results of the RUBIS modeling is compared with that of the analytical approach, we see that less wells are required when the analytical approach is used. This is probably due to the well spacing. When the analytical approach is used, it is assumed that the drainage areas of all wells are equal and this area is computed simply by dividing the area of the reservoir to the number of wells. Also interference effect is neglected in analytical approach. When RUBIS is used, if the wells are located closer, the drainage areas also become smaller. If the wells are located apart from each other, then the drainage areas become larger. The smaller number of wells required as half of the RUBIS modeling approach is probably due to interference effect that exists where the wells are located closer. A sensitivity of the location of wells has not been conducted in this study.

Table 4.7: The comparison of RUBIS model and analytical method results.

	RUBIS model		Analytical method	
	Production period	Injection period	Production period	Injection period
Horizontal wells	6	6	4	4
Vertical wells	12	16	9	12

5. CONCLUSIONS

This study discusses results of a modeling study on the underground gas storage design of a depleted gas field. The purpose of modeling was to determine the optimum number of wells to be used for withdrawal and injection operations. For the considered field, the original gas in place is assumed to be 5.1 billion Sm^3. The working gas volume is determined to be 2.07 billion Sm^3. On the modeling study, the optimization process was based on two different criteria. These are:

Criteria 1: Determination of the optimum number of wells to meet the peak day requirement (1/40 working gas capacity), after removing 75% of working gas content.

Criteria 2: Determination the optimum number of wells based on given wellhead flowing pressure constraints.

In the first criteria, two types of wells, vertical versus horizontal is considered in the design process. Deliverability equations and also theoretical equations were assumed to be representing the inflow performance relationship. In addition, the RUBIS software has also been used to model the reservoir. The effect of various factors such as skin factor, wellhead pressure and horizontal length are studied in this model. The results based on Criteria 1, can be listed as follows:

- To maintain the peak day requirement of 51.8 million Scf/D (1/40 working gas capacity) after removing 75% of working gas capacity in vertical wells, 35 vertical wells are required when a wellhead pressure of 70 bar is used. The wellhead pressure has significant effect on the performance of the underground storage reservoir. The number of wells required to maintain the same amount of working gas capacity becomes 21, if the wellhead flowing pressure decreases to 46 bar.
- For constant wellhead flowing pressure of 70 bar, 56 wells are required when 90% of working gas capacity is removed and 26 wells required when 60% of

working gas capacity is removed. The amount of produced working gas capacity has significant effect on the number of wells.

- The skin factor has a significant effect on the deliverability. If wells are stimulated and their skin factor is -2, then to meet peak day requirements a total of 17 wells are required. If a skin factor of 20 is used, the number of wells becomes 76.
- The horizontal length of the horizontal wells influences the number of required wells such that when the well length is 250 ft, 18 wells are required whereas if the well length increases to 1300 ft, the number of required wells decreases to 10.

The following results were obtained for Criteria 2:

- It is found that when wellhead pressure constraints are used, the required number of wells is dominated by the injection period. When computed separately the injection period always requires more wells due to compressor constraints. Based on the injection period computations, a total of 16 vertical wells are required. If horizontal wells with 300 m perforation length are used then a total 6 wells are required to be able to inject the gas at a given time of 150 days with a wellhead pressure constraint of 2000 psia.

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APPENDICES

APPENDIX A : About The RUBIS Software

APPENDIX A

RUBIS is a subprogram of the ECRIN software. RUBIS is a 3D three phase black oil simulator. In other words, the RUBIS simulator splits the reservoir into cells and then models the flow in the reservoir through applying mass balance equations to the each cell. Modeling with RUBIS is performed in eight stages. These stages are as follows:

1- Field general information
2- PVT definition
3- Field geometry
4- Petrophysical properties
5- Well information
6- Grid construction
7- Simulation characteristics
8- Initialization

These eight stage details are described in following sections.

A.1 Field General Information

In this section, general information related to the field is entered. This information is mainly the field name, company, country, starting time, and ending time of simulation. The reservoir boundaries and volume information are also entered at this stage. Figure A.1 shows screen where information is entered.

In addition, other information affecting the simulation process is available. This information consists of main option part allowing to RUBIS accounts for gravity effects during the simulation process. Moreover it is possible to initialize the RUBIS run by importing directly the contour and the reservoir volumes and properties from a geomodeler.

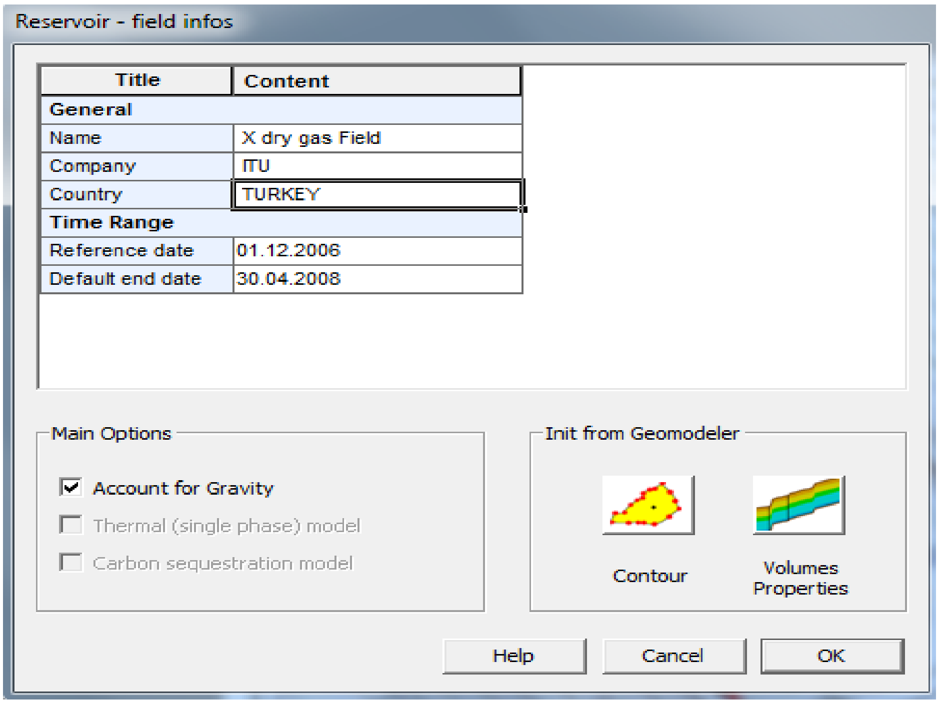

Figure A.1: The reservoir field information.

A.2 PVT Definition

In this part the reservoir fluid properties are assigned. The PVT definition window is given in Figure A.2. RUBIS is capable of handling dead oil, dry gas, saturated oil, condensates and any other PVT behavior provided by tables along with a water phase. All properties regarding the PVT of the fluid are given in this section.

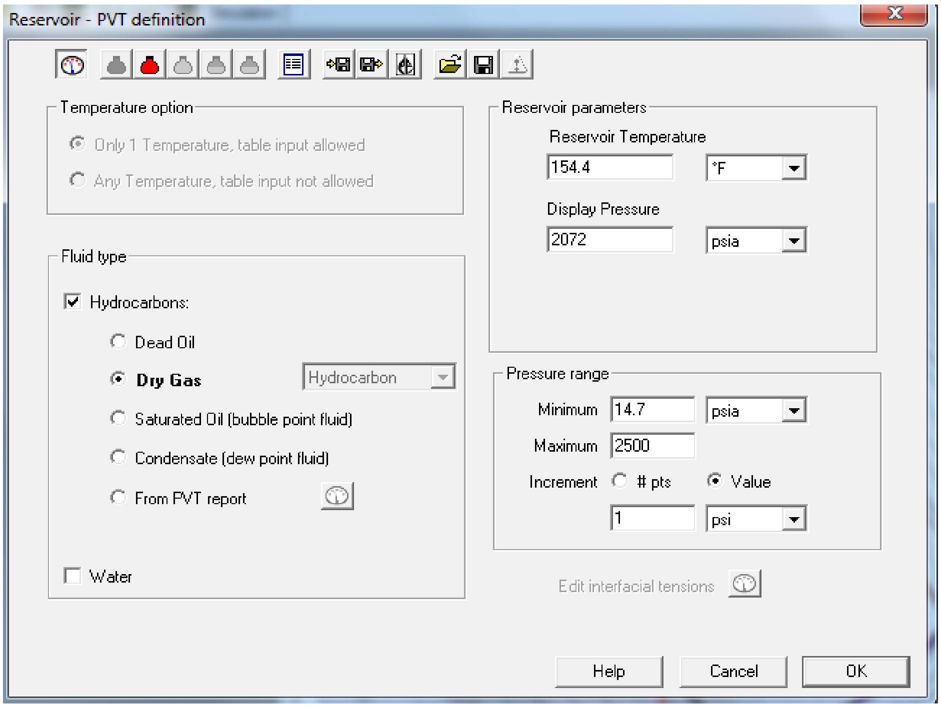

Figure A.2: The reservoir definition.

Fluid properties can either be provided as input or various correlations may be used. RUBIS provides most of the correlations used in the literature. Figure A.3 illustrates one of the windows.

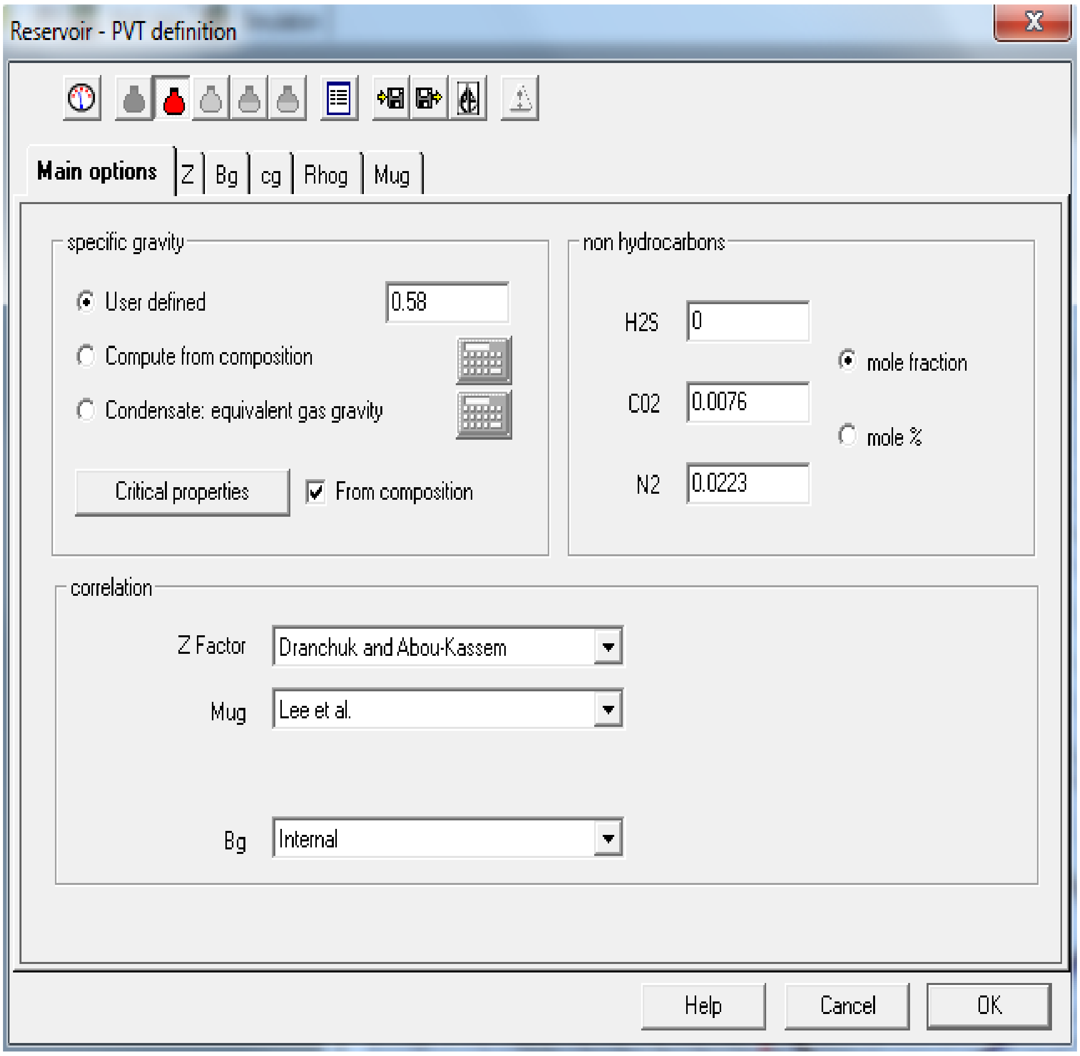

Figure A.3: The reservoir fluid properties.

A.3 Field Geometry

RUBIS provides the wide opportunities with working in different field geometries. In the reservoir geometry section, RUBIS gives the user to work with multiple layers with different geological properties. Furthermore varying different depths may be provided. The topology could also be varying. The user needs to input depth of the top of the reservoir at the various locations and RUBIS will use different types of interpolation tools to fill the entire topology. Figure A.4 illustrates the windows for the input of layers and Figure A.5 illustrates the windows for inputting the thickness.

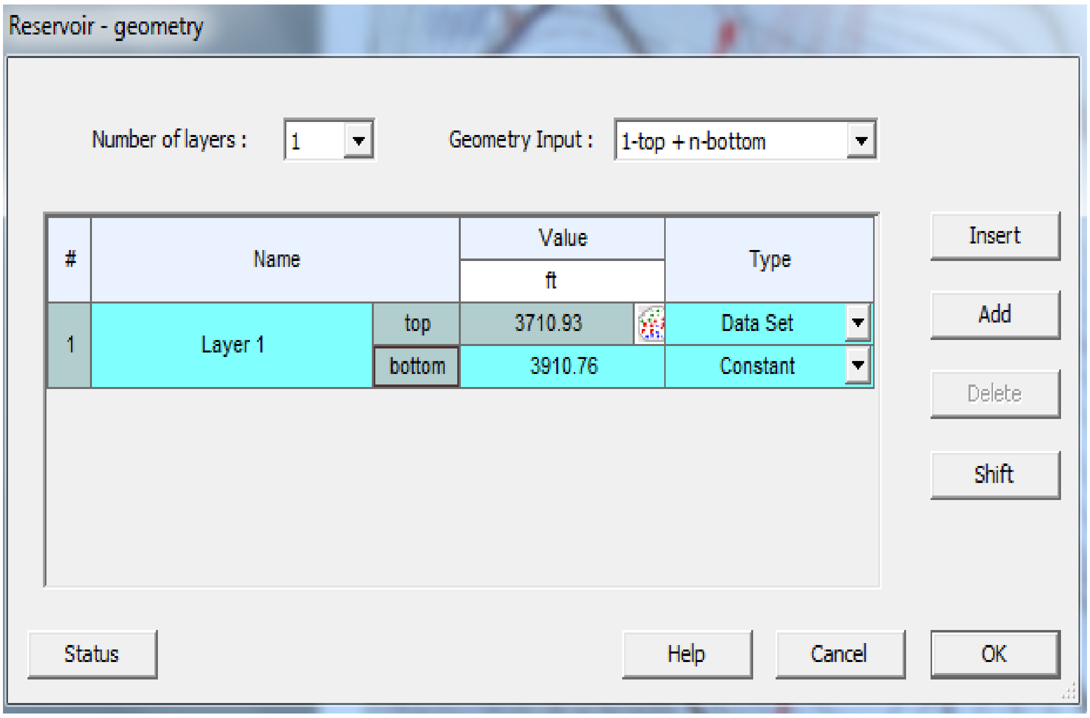

Figure A.4: The reservoir geometry window.

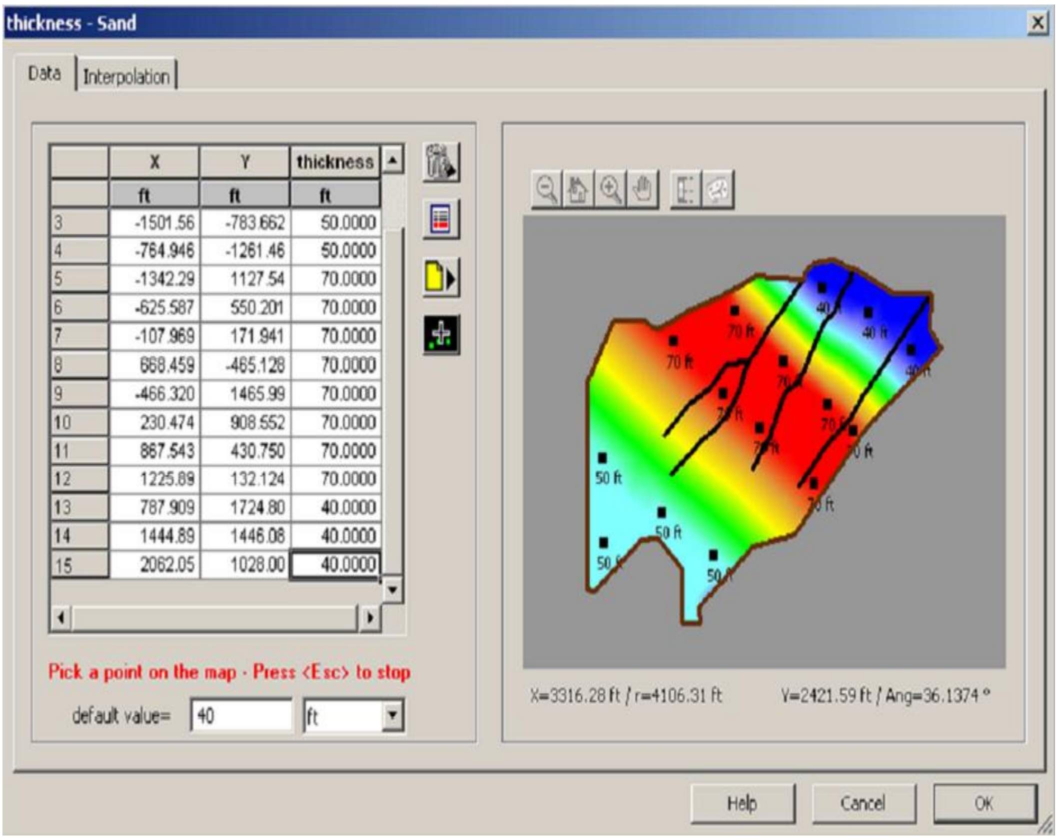

Figure A.5: The assignment of the field thickness.

A.4 Petrophysical Properties

In this part of the program, reservoir layering, reservoir properties and the initial state of the system are provided. The petrophysical properties are allowed to be either homogeneous or heterogeneous and anisotropy in both the vertical and horizontal directions. RUBIS allows for multiple layers as well as a composite type of reservoir. The reservoir properties windows is illustrated in Figure A.6.

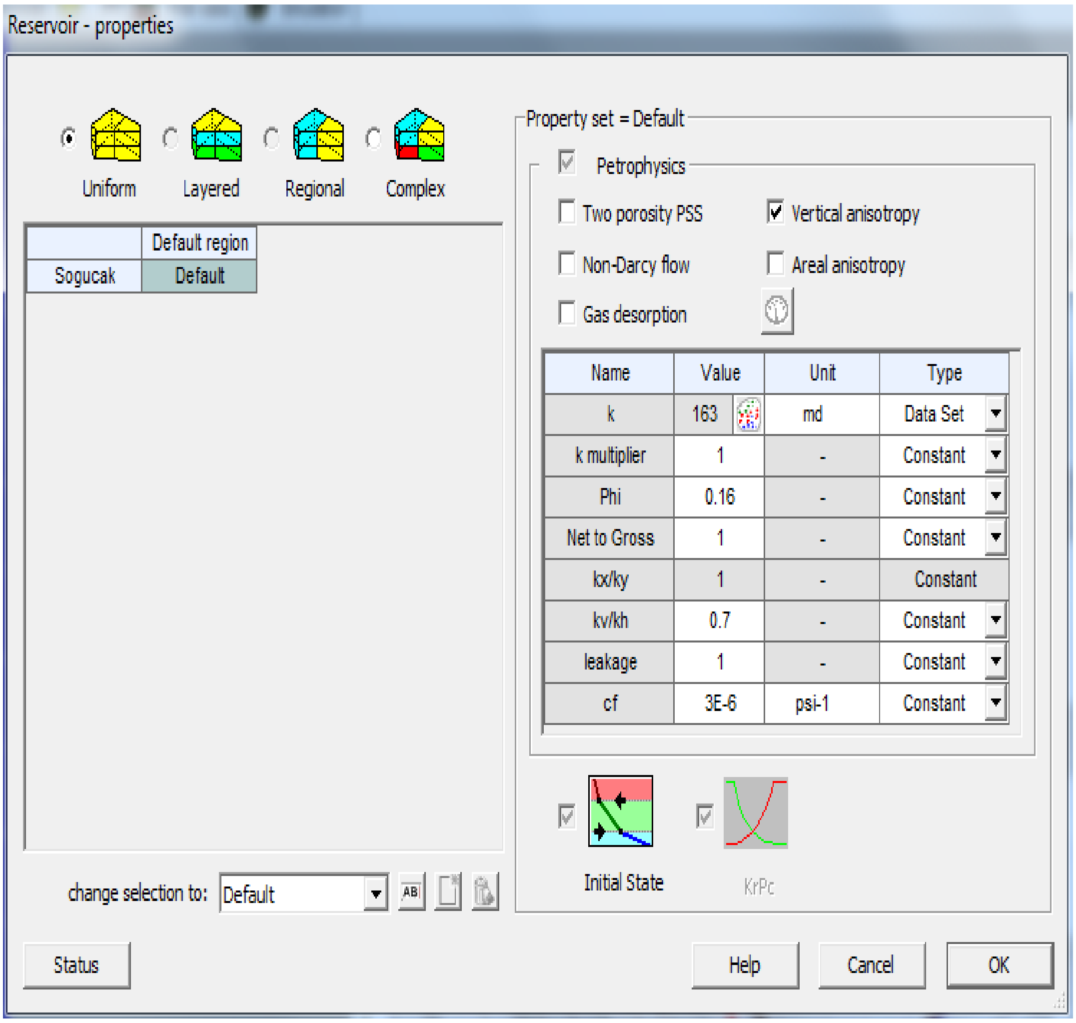

Figure A.6: The reservoir properties.

Figure A.7 shows the windows for the input of the initial pressure along with a refrence temprature and reference depth at which the initial pressure is measured. RUBIS allows user to enter GOC (gas oil contact) depth and WOC (water oil contact) depth in two or three phases condition.

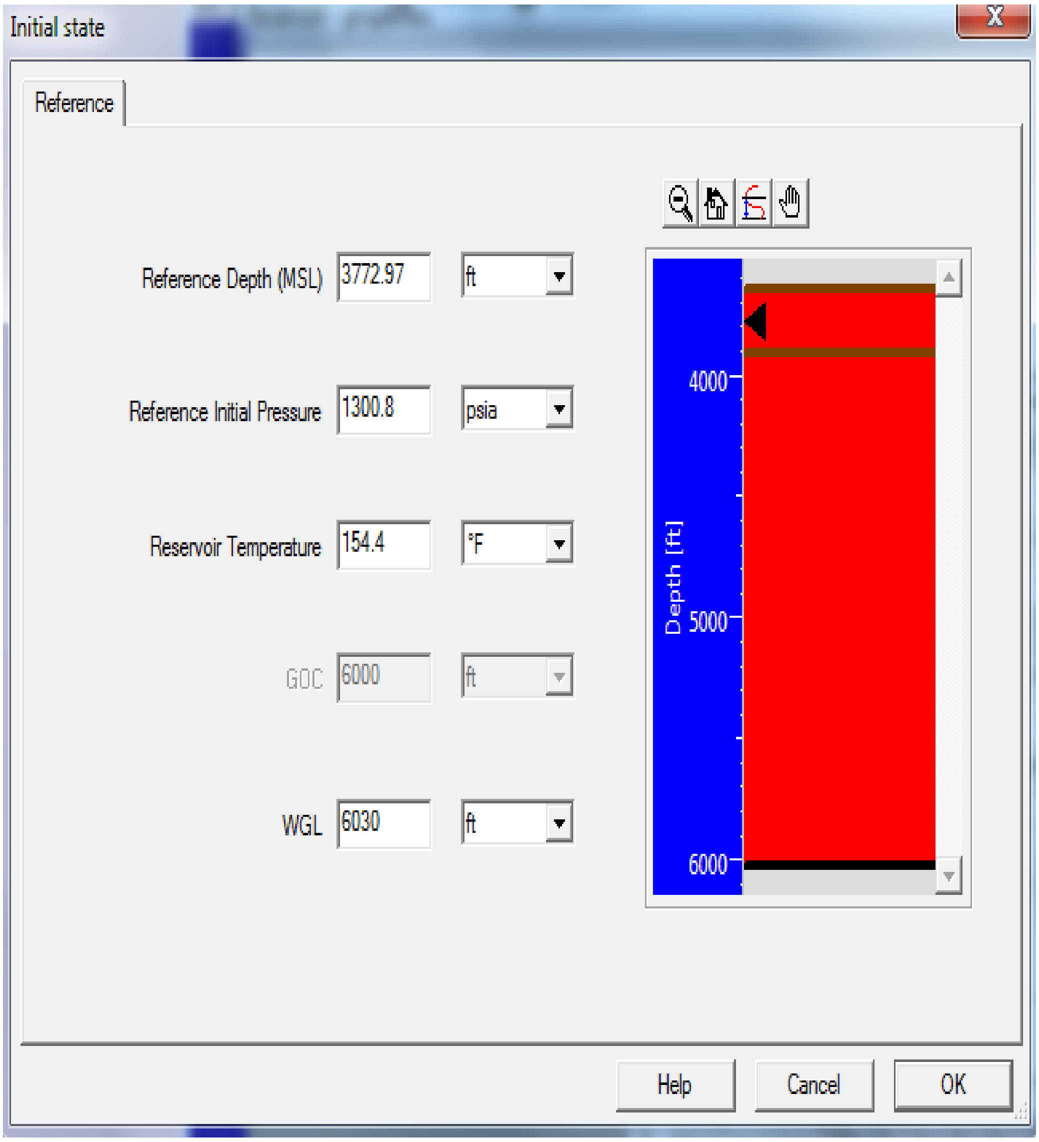

Figure A.7: Initial properties window.

A.5 Wells Information

In this section information regarding the wells and the production/injection schedule is given. RUBIS allows the use of vertical, deviated and horizontal wells. Figure A.8 illustrates the windows for providing the input to wells. As can be seen from Figure A.8, five main tabs are present to be used to provide well information regarding well geometry, perforations, wellbore properties and flow model, well data and well controls. In the geometry tab, geometry information such as deviation angle, true vertical depth, position of well, radius and etc, regarding the well are given. All information can be provided interactively.

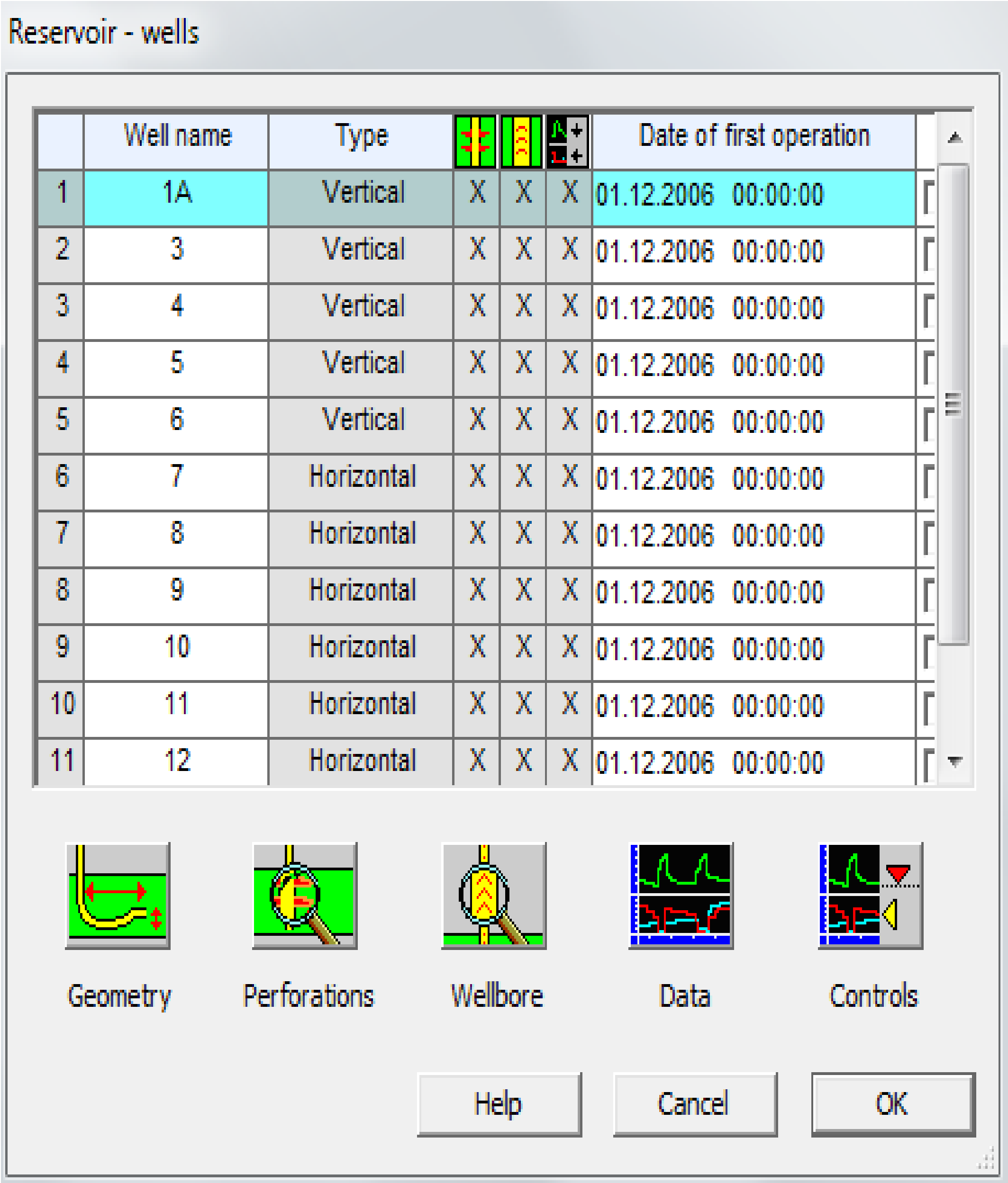

Figure A.8: The main windows of reservoir wells.

In the perforation tab, information regarding perforations is input interactively. RUBIS allows the user for fully penetrating wells as well as partially penetrating wells. Furthermore the skin factor is also input within this tab. The perforation tab window is illustrated in Figure A.9. In the wellbore tab, as seen in Figure A.10, the user can input information regarding the tubing and flow model to be used in the well. The data tab is used for inputting production data observed at wells to compare with actual simulator output for history matching purposes. The control tab is used to provide the schedule with which the wells will perform.

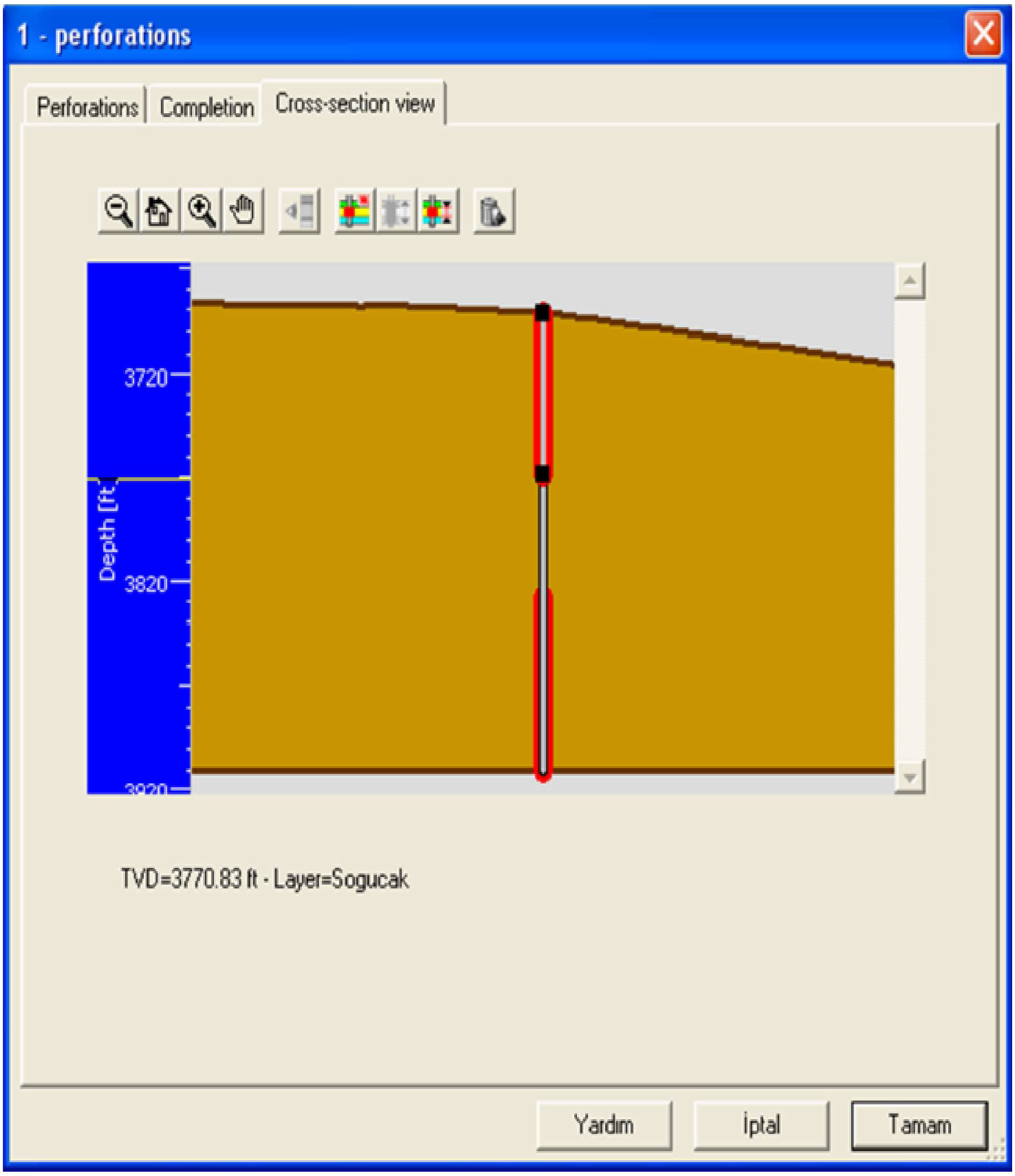

Figure A.9: Adding and positioning of perforation.

RUBIS gives the user to work with various production/injection schemes. For example for a gas well, the production could be carried out with constant wellhead pressure, constant bottom hole pressure, constant surface rate or constant bottom hole rate. Furthermore various constraints can also be provided. For example if the well is producing with a constant rate, a minimum bottom hole pressure constraint may be imposed such that the well switches to a constant bottom hole pressure production when the minimum bottom hole pressure is reached. Figure A.11 illustrates the well controls windows.

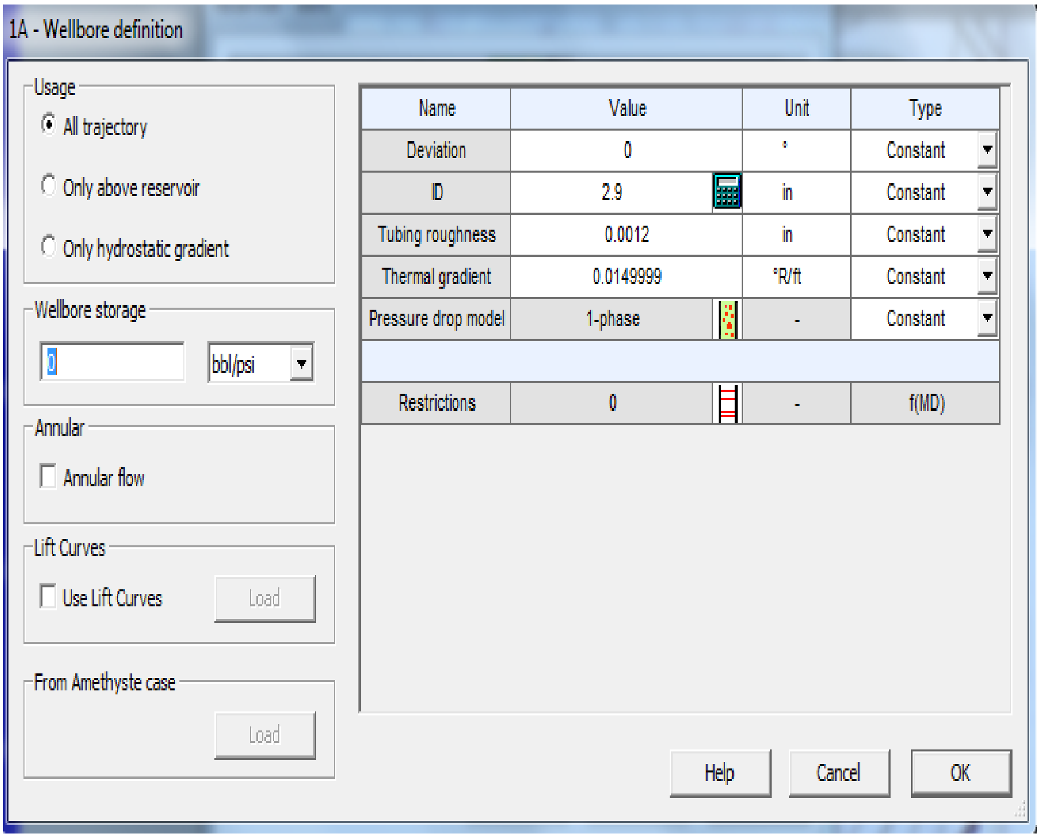

Figure A.10: Wellbore definition window.

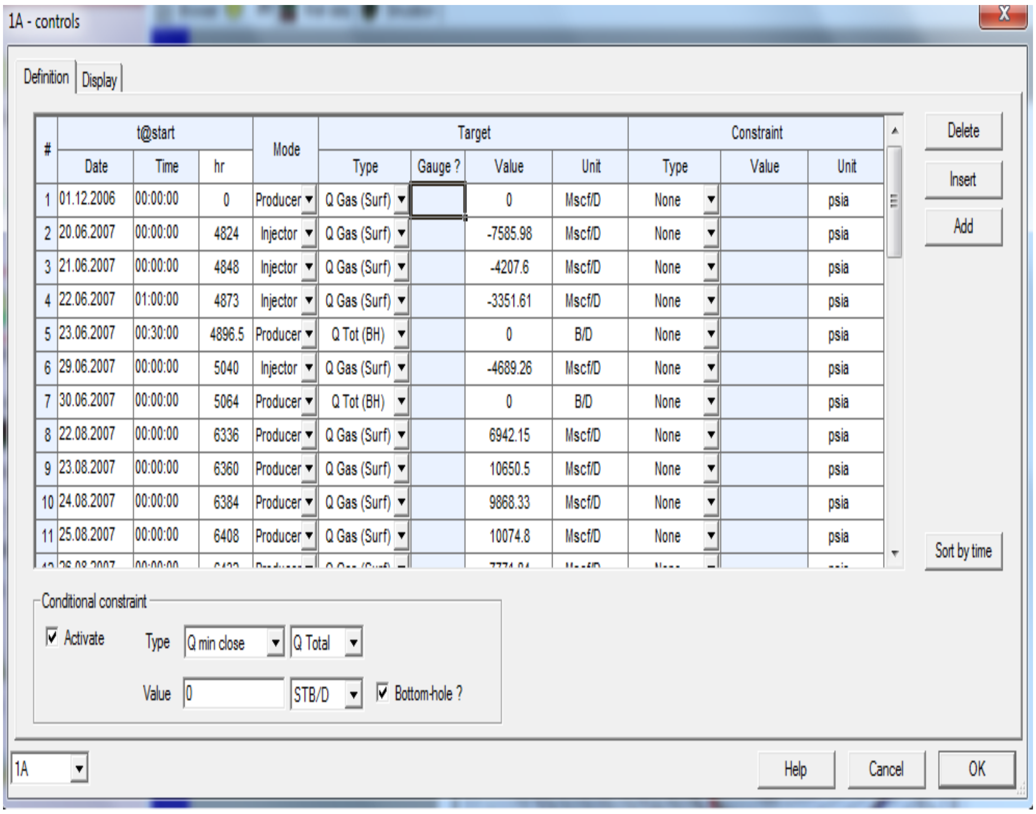

Figure A.11: The well control window.

A.6 Grid Construction

This dialog lists the various settings that control the construction of the RUBIS grid: number of cells in the background grid, number of sub-layer and so on. In this section the grids geometry may be set to hexagonal or rectangular. The geometry controls the shape of the background cells. The resulting grid is displayed in a 3D graph. This graph also displays the physical properties (k,Ø, etc…) that will be used in the following simulation run. Figure A.12 shows the 3D geometry plot of sample field permeability. Although hexagonal or rectangular grids are used for the reservoir, RUBIS mimics radial type grids around the wells for better representing radial flow.

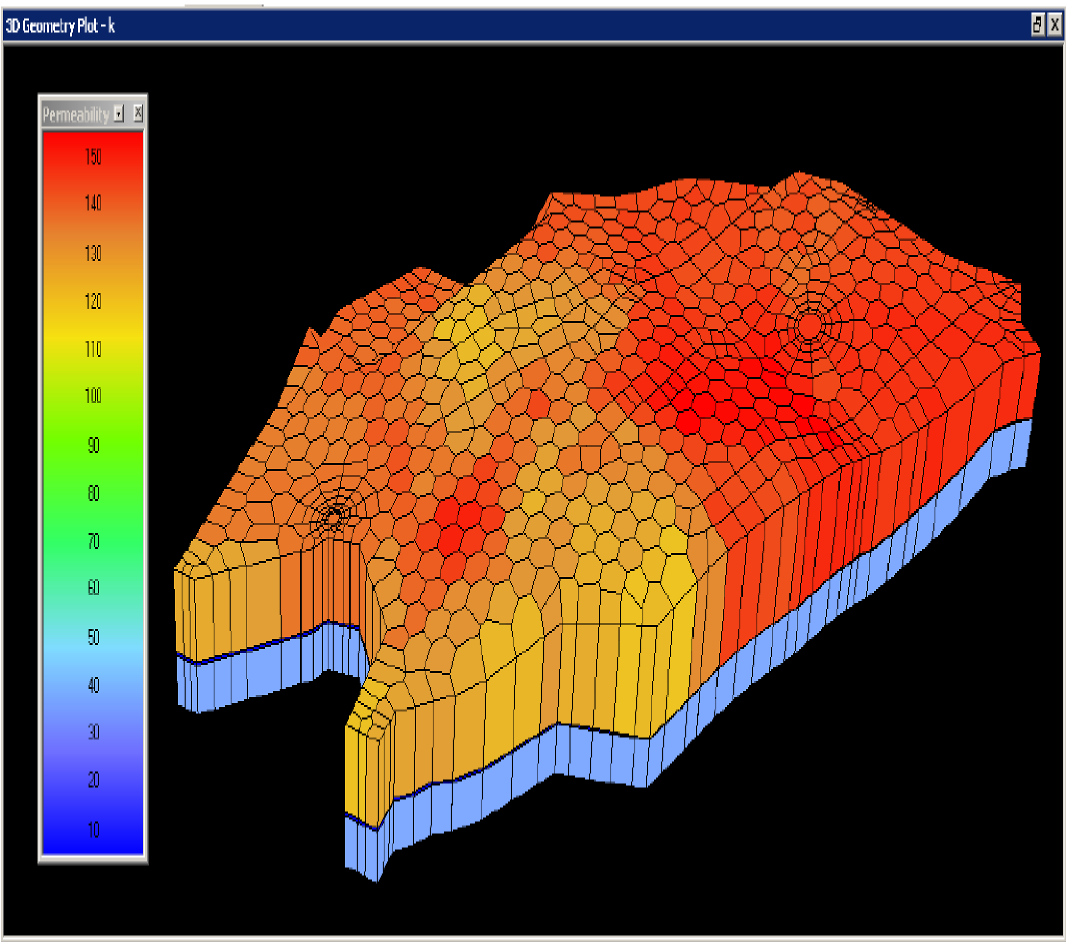

Figure A.12: Permeability field displayed in the 3D geometry plot.

A.7 Simulation Characteristics

In this section duration of the simulation and the types of the output results are determined. Figure A.13 shows the time setting tab in run settings window.

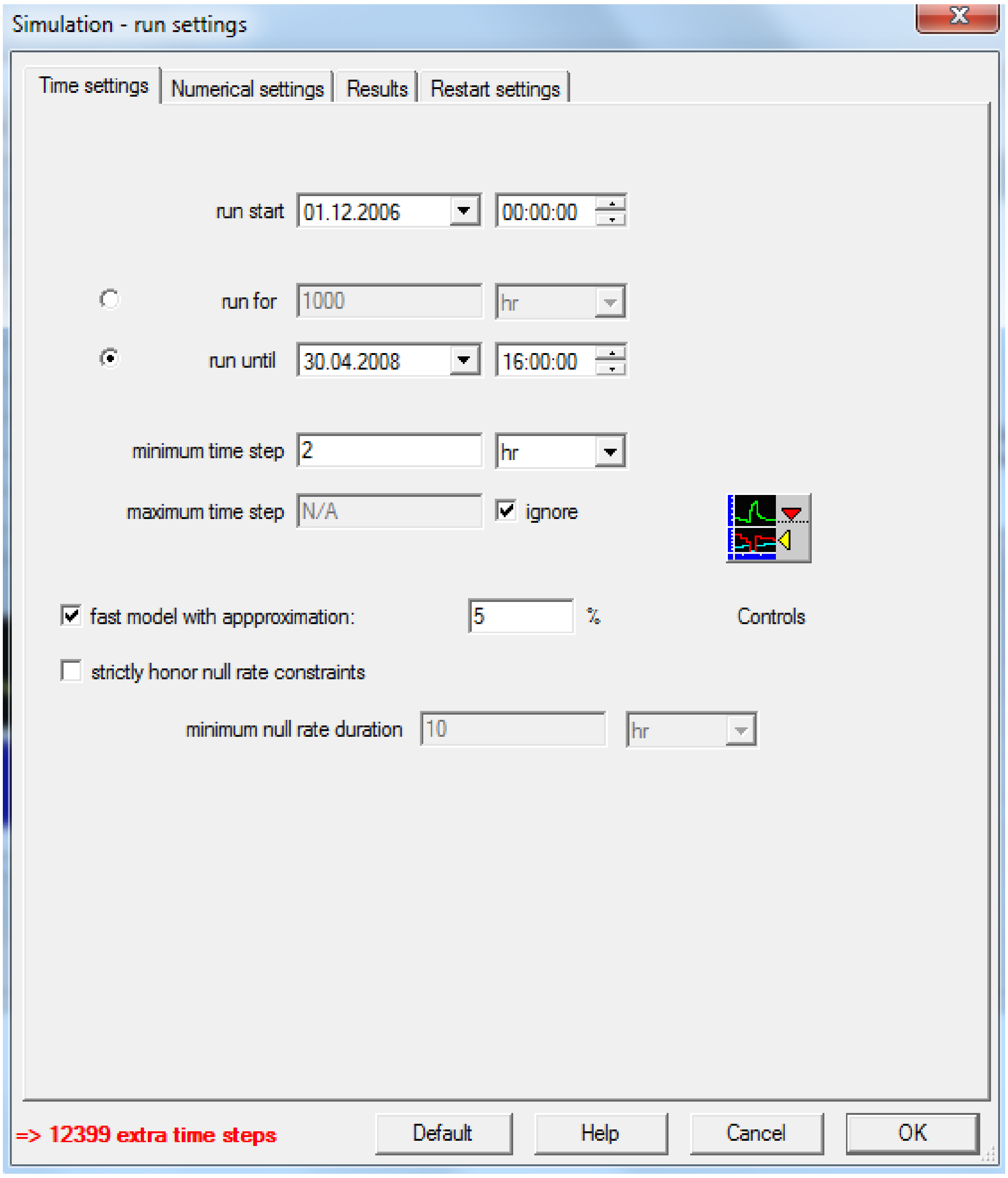

Figure A.13: Run settings tab of run settings window.

This window contains four tabs:

- The 'Time Settings' tab controls the duration of the simulation and other related aspects
- The 'Numerical Settings' tab permits to tune the numerical solvers
- The 'Results' tab allows for a selection of the desired output (gauges, well logs, output fields)
- The 'Restart' Settings tab controls the storage frequency of numerical restarts.

A.8 Initialization

In the initialization step, the reservoir is initialized. For example, for each cell the pressures are computed taking into account the gravity using the initial pressure at the reference depth. Similarly saturations are also assigned based on the HC contacts and the capillary pressure curves.

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